NERA
ECONOMIC CONSULTING

Managing constraint risk in the NZEM

Contact Energy

16 September 2020

Project Team

James Mellsop
Will Taylor, PhD
Barbara Kaleff

NERA Economic Consulting
Level 18
151 Queen Street
Auckland 1010
New Zealand
+64 9 9283292
www.nera.com

Contents

1. Introduction and executive summary

1.1. Introduction

1. On 12 December 2019 the Electricity Authority ("Authority") received a claim from seven participants that an "undesirable trading situation" ("UTS") had begun on 10 November 2019 and was continuing at the time of the claim.[1] The claim alleged the UTS consisted of Meridian Energy ("Meridian") and Contact Energy ("Contact") spilling water from their hydro generation stations in the South Island, while simultaneously offering the electricity they could have instead generated into the spot market at prices above short-run marginal cost ("SRMC").
2. The definition of a UTS in the *Electricity Industry Participation Code 2010* is:[2]
    a. any situation that threatens, or may threaten, the confidence in the integrity of the wholesale market; and
    b. that, in the reasonable opinion of the Authority, cannot satisfactorily be resolved by any other mechanism available under the code.
3. The Authority's preliminary view is there was a UTS during the period 3 to 18 December 2019. In particular, the Authority found that outcomes in the spot market over the period did not match its expectations, and that Meridian was offering in such a way as to ensure the High Voltage Direct Current ("HVDC") cable connecting the North and South Islands was not constrained.
4. The claimants also allege that Meridian and Contact's behaviour breached the high standard of trading conduct ("HSOTC") provisions. However, investigations of HSOTC provision breaches are not considered "another mechanism" under the UTS definition and the HSOTC investigation is being carried out separately from the current UTS investigation.[3]
5. We understand Contact's actions during the period of the UTS allegation were such that it:[4]
    a. Offered maximum capacity from its Clutha assets while managing a river in flood and accounting for outages and regulatory requirements; and consequently
    b. Offered high-priced tranches such that less generation would be dispatched to minimise marginal running and limit stress on safety equipment.
6. Accordingly, Contact's view is that its offer behaviour maintained consistency with the HSOTC provisions and does not constitute a UTS.
7. We have been asked by Contact to provide our independent review and comment on the submissions made in response to the Authority's preliminary decision. As well as any general comments we have, Contact has particularly asked us to provide our views on:
    a. The appropriate benchmark against which to judge offer behaviour, given the design of the wholesale market; and
    b. Given the existing market arrangements, the appropriateness of using offers to manage locational price risk.

---

[1] Electricity Authority, *The Authority's preliminary decision on claim of an undesirable trading situation: Claim submitted 12 December 2019 by Haast Energy Trading, Ecotricity, Electric Kiwi, Flick Electric, Oji Fibre, Pulse Energy Alliance, and Vocus*, 30 June 2020 ("Preliminary Decision"), p. i.

[2] *Electricity Industry Participation Code 2010*, Part 1.

[3] Preliminary Decision, p. iii.

[4] Submission from Contact, *Consultation on Undesirable Trading Situation (UTS) Preliminary Decision*, 18 August 2020, p. 1-2.

8. We understand our report will be filed with Contact's cross-submission to the Authority. We think our report may also be useful to the Authority in respect of its parallel HSOTC investigation.

1.2. Executive summary

9. A summary of our views is as follows:

    a. New Zealand has an energy-only wholesale market where generators receive the market clearing price, rather than the price they bid. Variable and fixed costs must therefore be recovered through a single per unit price. Like in most real-world, workably competitive markets, generators need to find opportunities to recover their fixed as well as their marginal costs. Price will need to exceed SRMC frequently enough, and by enough, to recover those fixed costs. Over time, electricity prices in a workably competitive wholesale market will average the long-run marginal cost ("LRMC") of new entrant power stations, although will spend periods of time both above and below this level.[5]

    b. Wholesale electricity markets involve extreme price volatility that end consumers typically do not want to bear. Retailers therefore provide a valuable service to consumers by bearing that risk. However, to offer this service retailers need a means to manage risk, which generally involves vertical integration or the contract market.

    c. New Zealand's wholesale electricity market is nodal. Transmission constraints mean that participants face locational price risk. Nodal prices are designed to provide locational signals for investment (other factors such as land and fuel availability can also have a determinative impact on locational decisions). But if the locational price risk cannot be managed, it can deter socially valuable decisions, such as expansion by a generator into retail at a different location or a willingness to enter into hedge contracts at nodes besides those which a participant is connected to.

    d. Financial transmission rights ("FTRs") can be used to manage this risk. However, at least given the current market arrangements and grid, FTRs are not a comprehensive tool to manage all locational risks. In particular:

        i. The hub model and scaling of the volume of FTRs sold in the auction to something less than the physical capacity of the line in question can leave participants exposed to locational price risk; and

        ii. Continuous FTRs covering a fixed volume for all dispatch intervals are a coarse hedge for:

            a. Irregular and short or high consequence events; and

            b. Plant with variable output and/or that only generate at certain times of the day.

    e. Accordingly, there are benefits from using offers to manage locational price risk. As the Authority has pointed out, there are also costs to using this mechanism. However:

        i. All risk management techniques involve a cost, which will ultimately fall on customers;

        ii. Using offers to manage constraints can result in a reallocation of the congestion rent without material (or indeed any) changes in dispatch/short run efficiency; and

        iii. There are costs to not having a tool to manage these risks (e.g., reduced retail competition).

[5] Marginal cost is the cost producing the next unit of electricity. SRMC is marginal cost measured over the *short run* and therefore excludes fixed and capital costs. LRMC measures the costs of producing the next unit of electricity over the *long run* and therefore includes fixed and capital costs.

f. Therefore, given the current market arrangements and grid, there may be net costs from an effective ban on using physical offers to manage constraint risk, even between nodes where an FTR exists. The current UTS investigation has not conducted an analysis of the costs and benefits of such a ban and nor is it the appropriate format to do so.

10. The remainder of this report is structured as follows:

    a. Section 2 describes and discusses the relevant features of the market design of the New Zealand Electricity Market (“NZEM”) and issues faced by generators given that design:

        i. Cost recovery in an energy-only market;

        ii. Price volatility and risk management;

        iii. Locational price risk under locational marginal pricing; and

        iv. Financial transmission rights as a risk management tool.

    b. Section 3 shows conceptually how offers can be used to manage constraint risk using stylised diagrams; and

    c. Section 4 discusses the efficiency of using offers to manage constraint risk.

2. Market design of the NZEM

2.1. Cost recovery in an energy-only market

11. Electricity generation is a capital-intensive business – generators have substantial fixed and capital costs they must recover.

12. The NZEM is an energy-only market – therefore fixed and capital cost recovery must occur through a single per unit price.[6] If outturn prices only reflect SRMC on average, there will be "missing money" and generators will not be able to recover their fixed and capital costs. Cost recovery, and therefore investment, in energy-only markets relies on either:

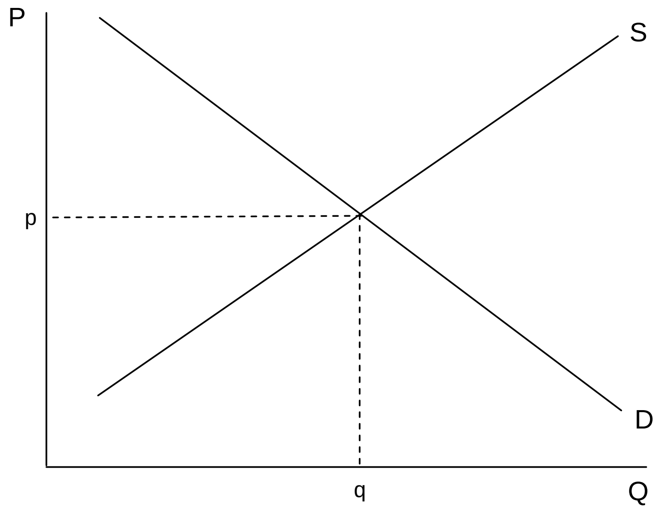
    a. Periods of both very high and very low prices, which result in an average price that provides for fixed and capital cost recovery; or

    b. Less volatile price levels that more closely equate to the price which provides for fixed and capital cost recovery.

13. This is not a problem limited to electricity. In most real-world, workably competitive markets, firms need to find opportunities to recover their fixed as well as their marginal costs (e.g., hotels will vary their room rates based on demand ("yield management") but will seldom price down to SRMC).[7] Indeed, over time workably competitive market prices will average the LRMC of new entry, as we now describe.

14. In a competitive market, price is set at the intersection of the market demand and supply curves, as illustrated in Figure 2.1. This applies whether the market is perfectly or workably competitive, with the main difference being one of timing – the "real world" features of workably competitive markets mean that the "equilibrium" depicted in Figure 2.1 may take some time to achieve after shocks occur. Nevertheless, the principle remains the same.

Figure 2.1: Competitive price setting



[6] An alternative to an energy only market is a market with capacity payments, whereby generators are paid for both the energy they produce and for having capacity available.

[7] For example, *Lodging* states: "Variable costs may range from $12 per room night for a budget property to more than $75 per room night for a world-class hotel." http://lodgingmagazine.com/what-are-your-true-variable-costs-per-occupied-room/. *Lodging* describes itself as "the official publication of the American Hotel and Lodging Association". We assume these figures are in USD, but it is not necessarily appropriate to simply convert them into NZD at the nominal exchange rate.

15. The firm that produces at the intersection of market demand and supply is the "marginal firm". Therefore, price in a competitive market (generally) equals the marginal cost of the marginal firm.

16. Of course, that marginal firm would seek to recover its fixed costs. Consider the investment decision that the marginal firm made when it entered. The marginal firm would have entered the market only at the point when its expected revenues from entry equalled or exceeded its expected entry costs, both capital and operating. At the time of entry, the firm's costs included the capital costs (replacement cost) of the required assets. So, the marginal firm only entered when the expected price covered its expected costs (including any sunk components) of entering. Put another way, a firm would only have entered if price exceeded the LRMC of expanding capacity. Therefore there is a link in competitive markets between LRMC and price.

17. Furthermore, the link will remain as costs change, or other shocks occur. For example, if price is currently higher than LRMC (e.g., due to an increase in demand or a reduction in costs), entry would (eventually) occur until the point at which price covers, but does not exceed, the cost of expanding capacity.

18. Similarly, if the price is less than LRMC (e.g., due to a decrease in demand or an increase in costs), then assets would not be replaced when they expire and capacity would eventually leave the market until the point when price equals LRMC again. Note that this would not happen instantly, but rather supply would exit the market in the long run (unless demand recovers).

19. The fact that there is a dynamic link in competitive markets between LRMC and price does not mean that the price in a competitive market will always equal LRMC. Real-world markets, unlike hypothetical perfectly competitive markets, take time to respond to changes in cost or other shocks due to factors such as imperfect information, transaction costs and lumpy, long-lived investments. There will be times when the price is lower and times when the price is higher. However, in the long run price will trend towards LRMC even as LRMC moves around.

20. The High Court decision in *Wellington International Airport Ltd and others v Commerce Commission* made a similar point:[8]

> *Of course, firms may earn higher than normal rates of return for extended periods. On the other hand, firms may earn rates of return less than they expected and less than commensurate with the risks faced by their owners when they made their investments. They may even make losses for extended periods. Prices in workably competitive markets may never exactly reflect efficient costs, including a normal rate of return.*
>
> *But the tendencies in workably competitive markets are towards such returns and prices.*

21. The combination of the energy-only nature of the NZEM and the fact that in workably competitive markets prices are generally never precisely equal to the level that would cover LRMC requires that generators take what opportunities they can to recover their (substantial) fixed costs. Meridian's general offer strategy, as described in its submission, reflects this.[9]

22. In the real-world wholesale electricity market, generators will also be cognisant of resource consent constraints, managing plant wear and tear, and the opportunity cost of fuel.

23. Markets that do not allow infrequent but very high prices or prices that are persistently above SRMC, such that the average unit price generators receive covers their fixed and capital costs, will suffer from the "missing money" problem. This has led some markets to implement a

[8] *Wellington International Airport Ltd and others v Commerce Commission* (2013) NZHC 3289, at 19-20.

[9] Generally Meridian structures its offers in three tranches: a large portion of its generation is offered at prices close to zero to meet load; additional generation in excess of contracts is offered to deliver optimal volume and prices; and smaller volumes of generation are offered such that they are not intended to clear. See Meridian, *Meridian Submission: Preliminary decision on claim of an undesirable trading situation*, 18 August 2020 ("Meridian submission"), p. 20..

capacity market, where generators receive separate fixed payments for having capacity available. This is essentially the point made by Brattle.[10]

2.2. Volatility and risk management

24. Electricity is a product with unique features that result in volatile prices, including that:

    a. Demand on the grid must be balanced in real time, which means that electricity produced at different times may have very different value to consumers (or large retailers on their behalf);

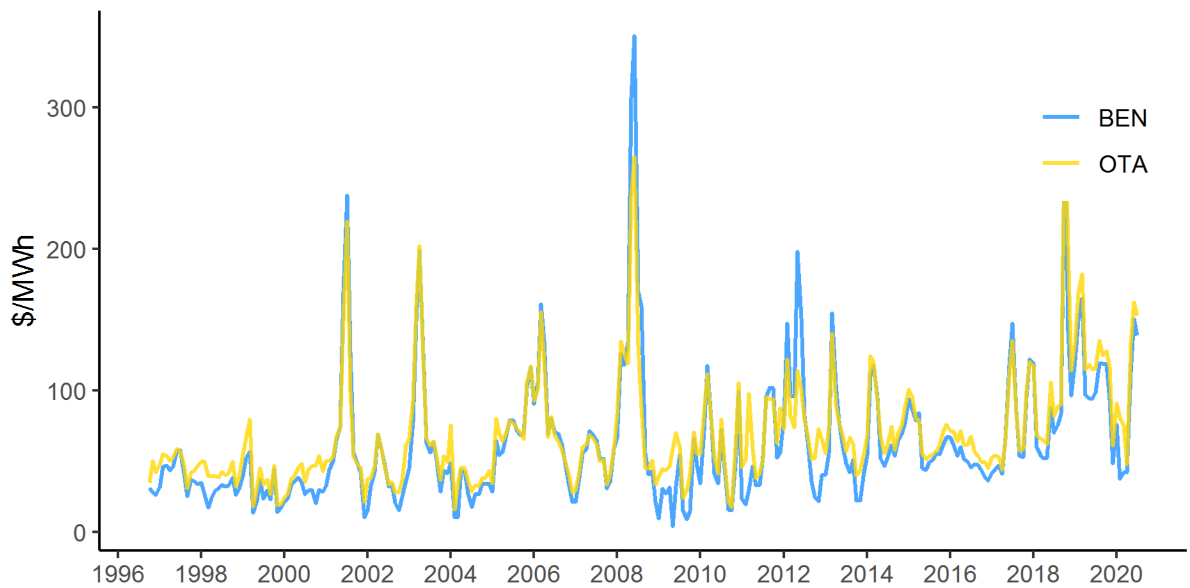
    b. Both demand and supply can vary in unpredictable and unrelated ways[11] which, when combined with the costs of committing units to generate ahead of time, increases volatility and exposes both generators and retailers to price and volume risk;

    c. The demand side is largely passive in the short run and very inelastic (although this is changing with, for example, the advent of smart meters and retail spot pricing); and

    d. The costs of the storage that would flatten prices can be prohibitive (albeit falling).

25. Therefore, while we would expect prices to track LRMC over time (see section 2.1), the unique features of electricity markets mean that wholesale prices can vary wildly in the short run, and over the medium term as more prolonged supply and demand shocks occur (the key shock resulting in sustained periods of high prices, in the New Zealand context, being a "dry year").[12] Figure 2.2 and Figure 2.3 below demonstrate that volatility in the NZEM.

Figure 2.2: Long run volatility – monthly average spot price at Benmore and Otahuhu nodes



Source: NERA analysis of EMI data.

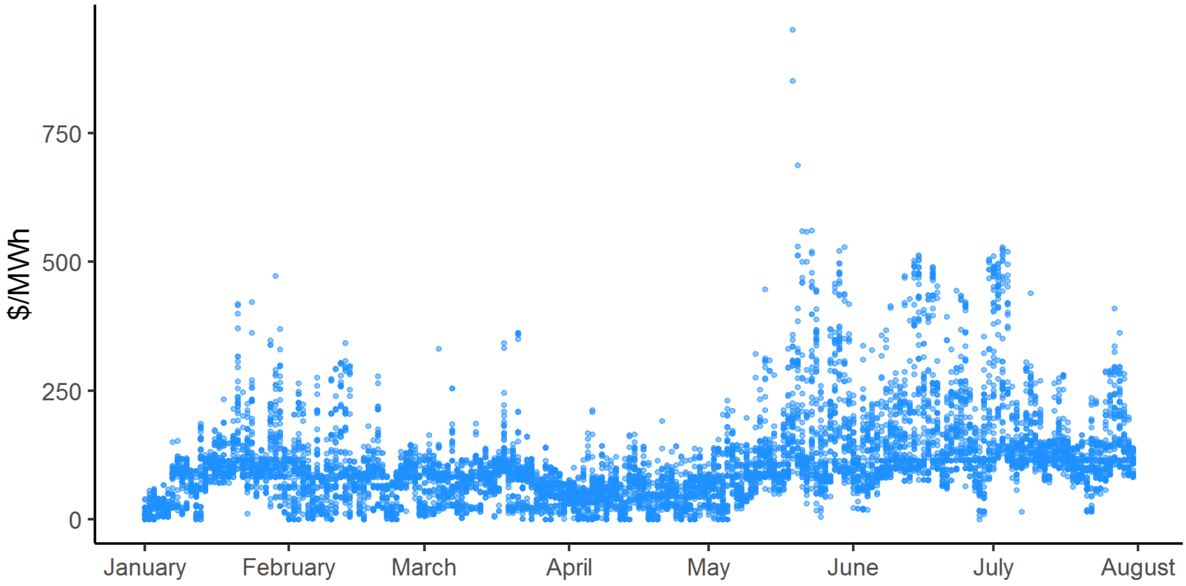
---

[10] The Brattle Group, *New Zealand Electricity Authority's Preliminary Decision on UTS*, 18 August 2020 ("Brattle Report"), paras 6 and 41.

[11] For example, both demand and supply can be affected by the weather, but the effect on each will not always be the same if the weather is different where generation and demand are located.

[12] A dry year being a period of sustained low hydro inflows in the South Island. This is therefore the opposite of the situation during the alleged UTS which was a period of high inflows.

Figure 2.3: Short run volatility – half hourly prices in 2020 at the Otahuhu node



Source: NERA analysis of EMI data.

26. If consumers were happy to pay a price that varied dramatically every 30 minutes, this would not be an issue – retailers would simply pass these volatile prices onto consumers through retail tariffs that varied in line with movements in the wholesale market. Consumers on the whole, however, appear to desire fixed prices[13] and therefore retailers need a means to manage wholesale price volatility in order to offer consumers fixed retail prices. A retailer that offers a fixed price to customers but faces the volatile wholesale electricity price as one of inputs, or a generator that is not hedged, would face significant volatility in its cashflows and profits.

27. Risk management allows retailers to offer a product that consumers value and is critical to the success of business in the electricity industry. This is achieved in the NZEM through vertical integration (which results in the risks faced by the retail and wholesale business units offsetting each other) and the use of the contract market (which allow participants to trade electricity for a fixed price).

28. Hedge contracts require counterparties that are willing to contract over a common reference price. In New Zealand's nodal system, if a generator is located in the South Island and faces the Benmore price, it may not be willing to sign hedge contracts that reference the Otahuhu price, as this would expose that generator to basis risk (i.e., the risk that the Otahuhu and Benmore prices differ). A well-functioning hedge market (which benefits consumers) therefore either relies on participants facing the same price or having a means of managing the basis risk created by counterparties facing different wholesale prices. In this context, we now explain the nodal pricing system used in the NZEM and FTRs.

2.3. Locational price risk under locational marginal pricing

29. NZEM is also a nodal market, with both generation and load facing a "locational marginal price" ("LMP"). LMPs are set equal to the marginal cost (based on generator bids) of supplying an additional increment of generation at the node in question. In the absence of losses and congestion, power can flow freely around the network and all prices would be equal. A key benefit of nodal pricing is that it provides locational signals on where new generation (and load)

[13] We note the recent emergence of spot price retailers, such as Flick and Electric Kiwi.

should locate – locating new generation very far from demand (which would result in higher losses) or "behind" a constraint provides less value to the grid from a total system cost perspective than locating the same plant close to load or at a non-congested node, all other things being equal.[14] Differences in nodal prices also provide information on the value of relieving transmission constraints.

30. LMPs are therefore explicitly designed to reflect both losses and congestion. The alternative is to have a form of zonal pricing in which the prices would not reflect localised congestion[15] (but could still reflect losses through settlement). Therefore, inherent to nodal markets is a design decision to expose market participants to constraint risk.

31. In the New Zealand context, where the majority of load is in the North Island but roughly half of generation is in the South Island, the key constraint is the HVDC.[16] When the HVDC binds, this can result in price separation, with prices being lower in the South Island than the North Island if the marginal plant in the North Island is more expensive than the marginal plant in the South Island. This reflects the lower *marginal* value of an additional unit of generation in the South Island, given the constraint on transporting generation to load in the North Island. As a manifestation of locational *marginal* pricing, this means all South Island generation receives the lower *marginal* price, despite the fact that the exported generation collectively adds more value to the system than the additional marginal unit that sets price.[17] This is reflected by the resulting "congestion rental" whereby North Island load pays a higher price for the imported generation than South Island generators receive for sending it.[18]

32. Figure 2.4 below sets out diagrammatically the prices that result when there are no transmission constraints (and therefore no price separation) and when there is a binding transmission constraint.

[14] Of course, all other things are generally not equal and factors such as fuel availability (in the case of thermal and hydro generation) and weather (in the case of solar and wind generation) can be determinative factors in where generation locates.

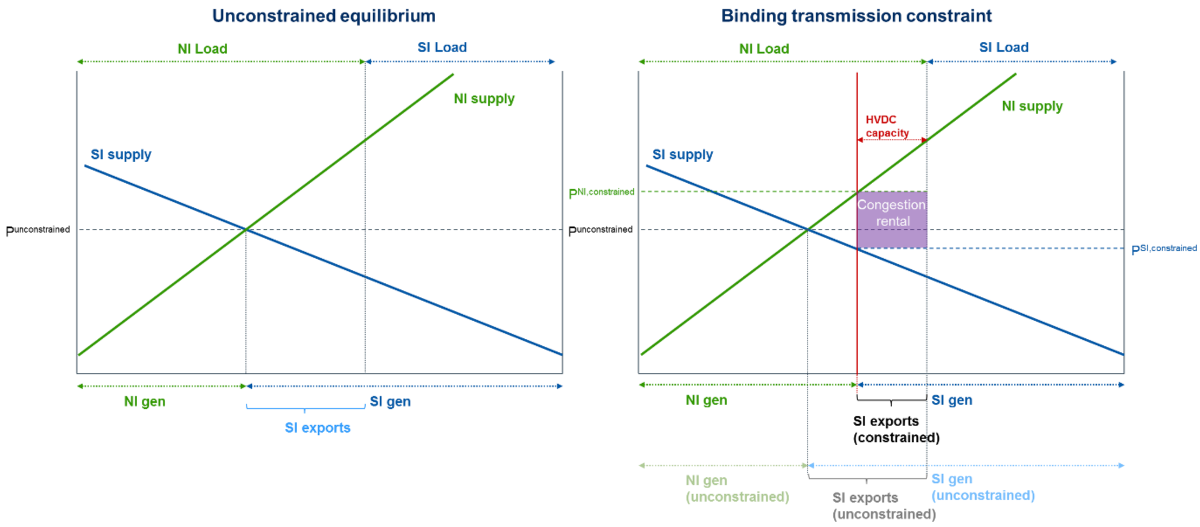
[15] This is the current approach adopted in Australia where there are five zonal prices in the National Electricity Market (NEM) corresponding to the different states in Eastern Australia. A zonal approach also previously existed in the United States prior to all major markets transitioning to nodal pricing. Similarly, Australia is currently in the middle of a reform process considering implementing LMP in the NEM.

[16] In December 2019, 49% of electricity was generated in the North Island and 51% in the South Island, while 60% of electricity demand was in the North Island and 40% in the South Island. For all of calendar year 2019, 54% of electricity was generated in the North Island and 46% in the South Island, while 63% of electricity demand was in the North Island and 37% in the South Island. [Electricity Authority, Energy Market Information, Grid demand trends and grid generation trends, https://emi.ea.govt.nz/, accessed 27/08/20]

[17] In other words, the average value is greater than the marginal value.

[18] Specifically, the congestion rental is equal to the difference in prices multiplied by the flows over the constrained line.

Figure 2.4: Stylised representation of equilibrium prices and generation with and without a binding transmission constraint



Source: NERA analysis.

33. The first panel shows that in the absence of transmission constraints, price would be equalised across both islands at a level where the marginal cost of additional imported power from the South Island would equal the marginal cost of generating another unit in the North Island. The second panel shows a situation where export capacity is constrained at a level below the unconstrained level of exports in the first panel (represented by the South Island supply curve essentially becoming vertical once exports reach the limit of the HVDC). As a result of the constraint, less power is exported from the South Island than would be efficient in the unconstrained world and the price in the South Island consequently drops. More expensive generation must be dispatched in the North Island to meet load, which results in the North Island price rising.

34. This illustrates the basis risk point in relation to signing hedge contracts described in section 2.2 above. When a constraint binds, the prices in the North Island and South Island differ, which means a South Island generator that has entered into a hedge contract that references the Otahuhu node is now exposed to the difference between the North and South Island price two prices.[19] Given the asymmetry in the location of load and generation in New Zealand, for South Island generators to offer hedges to North Island retailers requires South Island generators to have a way of managing locational price risk.

35. Note that in this stylised diagram, the North Island price rises more than the South Island price falls. This means if the transmission constraint is relieved by expanding the capacity of the line, the North Island price would fall by more than the South Island price would rise.[20] This is the

[19] If Generator N sells a hedge at the Otahuhu node, it would be obligated to pay the load counterparty the difference between the higher constrained price and the contract price (for simplicity, assume this is the unconstrained price). If Generator N were located at Otahuhu, this would be offset by receiving a higher spot price for its generation, leaving the generator unaffected (i.e., the net price the generator receives would still be the contract price). However, Generator S in the South Island sells the same hedge at Otahuhu and also pays out the difference between the Otahuhu price and the contract price. But instead of receiving a higher wholesale spot price that offsets this payment, it would receive the lower South Island spot price. Signing the hedge contract at Otahuhu therefore leaves Generator S completely exposed to differences in the two prices in a way that Generator N is not.

[20] Note that this occurs due to the slopes and positions of the supply curves we have drawn.

"price smoothing" effect mentioned in the Sapere report whereby eliminating congestion can improve consumer surplus.[21]

36. These diagrams also illustrate the congestion rental that arises, indicated by the purple shaded area. This arises because South Island generators receive the lower South Island price for power that is exported over a constrained line, but for this same power North Island load pays the higher North Island price. The congestion rental is the North Island versus South Island price differential multiplied by the quantity of generation that flows across the congested line. A binding constraint triggers a transfer of value away from generators upstream of the constraint and load downstream of the constraint (in the form of the congestion rental)[22] to parties who hold FTRs and parties entitled to receive the loss and constraint excess ("LCE").[23] This means as the constraint approaches binding, a difference in one unit of generation can alter whether the value provided by South Island exports to the North Island sits with South Island generators or not.

2.4. Financial transmission rights as a risk management tool

37. To help with the management of locational price risk, FTRs were introduced in 2013.[24] FTRs are a financial instrument that pays out the price difference between a pair of nodes. This price difference is equal to the congestion rental in Figure 2.4 above. FTRs therefore allocate the congestion rental to holders of FTRs.

38. At present in New Zealand, there are eight FTR hubs (at nodes) across both islands.[25] For each pair of hubs there are two FTR products, one where the first hub is the source of energy and the second is the "sink" where energy exits, and vice versa – each of these two products is further sold as either an "option" (which only settles if the payout is positive) or "obligation" (which settles even if the payout is negative, meaning the owner makes a payment on it). The majority of FTRs are sold as options.[26] Both of these products cover a specified future month-long period, including every dispatch interval in that period.[27] It follows that there are four products sold for each pair of hubs, meaning there are currently 112 FTR products available,[28] sold in increments of 0.1MW.[29]

39. Two auctions are held each month: an "initial" auction at the start of the month and a "variation" auction in the middle of the month.[30] The initial auction allocates FTRs that are being made available for the first time, while variation auctions offer FTRs that have already had some initial

[21] Sapere, *The Authority's preliminary decision of an undesirable trading situation: An economic perspective*, 17 August 2020, para. 78.

[22] We are not claiming this is necessarily a pure wealth transfer (a price change that has no underlying resource efficiency implications), given this is precisely what LMP is intended to reflect.

[23] We expand on the definition of LCE and who is entitled to receive it in section 2.4.

[24] Electricity Authority, *Overview of the FTR market*, 2017, p. 6.

[25] Energy Market Services, *FTR Manager Monthly Report*, December 2019, section 3.

[26] Electricity Authority, *Overview of the FTR market*, 2017, p. 5.

[27] Electricity Authority, *Financial Transmission Rights development: Issues and options paper*, 28 March 2017, 3.6.

[28] Energy Market Services, *FTR Manager Monthly Report*, December 2019, section 3.

[29] Electricity Authority, *Overview of the FTR market*, 2017, p. 5.

[30] Electricity Authority, *Overview of the FTR market*, 2017, p. 5.

supply allocated during the primary auction, or are being resold.[31] FTRs may also be resold through private trade.[32]

40. FTRs are funded by the auction income (i.e., what the participants pay to hold the FTR) and the LCE (i.e., the surplus created in the market after purchasers have been invoiced and generators have been paid).[33] However, not all of the LCE created is used to fund the FTRs, as FTRs do not cover all grid electricity flow. When FTR settlements are paid, additional surplus is transferred to Transpower to allocate to transmission customers. In the event that there is not enough money to settle the FTRs ("revenue inadequacy"), all FTR payments are scaled back to match the available funds.[34]

[31] Electricity Authority, *Financial Transmission Rights development: Issues and options paper*, 28 March 2017, 3.14(b) and (e)(i).

[32] Electricity Authority, *Financial Transmission Rights development: Issues and options paper*, 28 March 2017, 3.14(e)(ii).

[33] Electricity Authority, *Overview of the FTR market*, 2017, p. 4.

[34] Electricity Authority, *Overview of the FTR market*, 2017, p. 4.

3. Managing constraint risk using offers in concept

41. The Authority's characterisation of the behaviour in question is that:[35]

    a. Meridian offered its South Island generation in such a way so as to ensure the HVDC was not constrained;

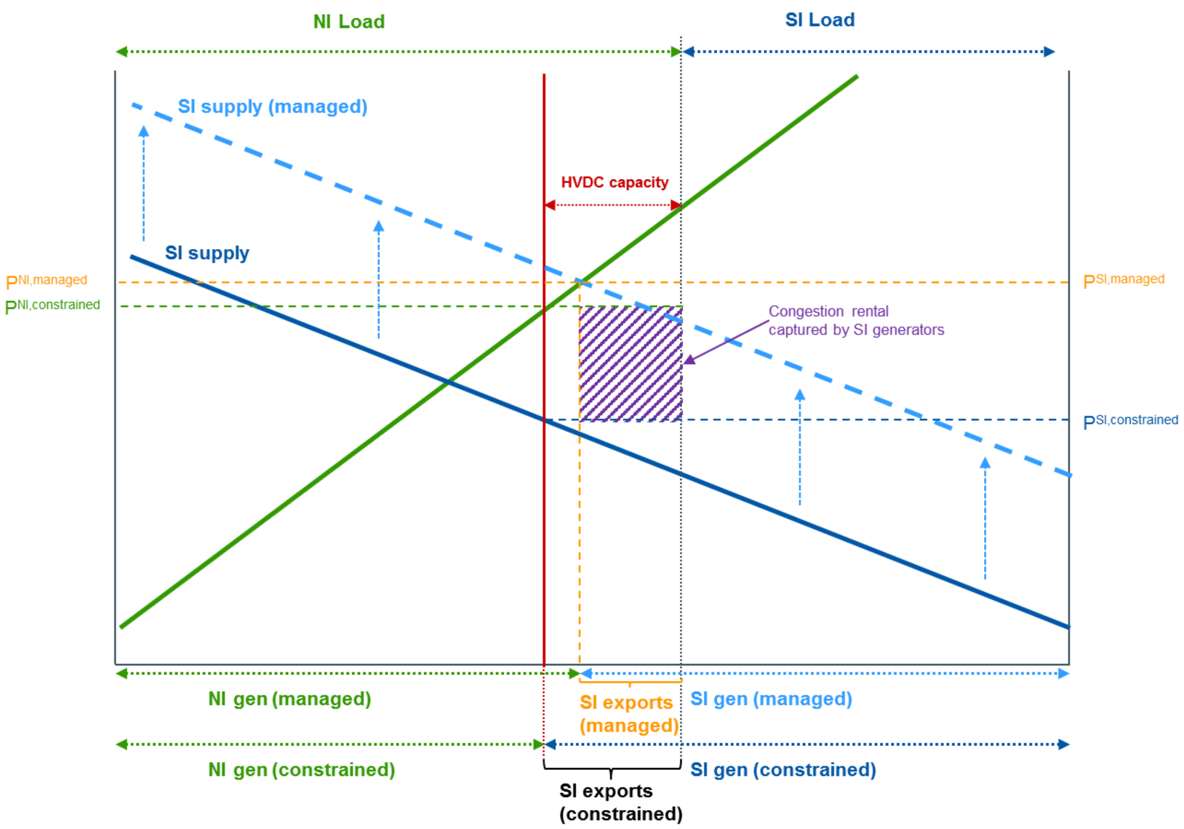
    b. This prevented price separation from occurring;

    c. Price separation between the North Island and South Island would have resulted in prices in the South Island being lower than prices in the North Island; and

    d. There were periods where thermal generation ran in place of South Island generation that was spilling when there was available capacity on the HVDC.

42. In Figure 3.1 below, we present a highly stylised diagram illustrating this characterisation of events in December 2019, building on the stylised diagrams in section 2. We illustrate the potential outcome of the Authority's characterisation as an upward shift in the South Island offer curve, on the basis the Authority is alleging Meridian bid its supply in at a level above its opportunity cost.

Figure 3.1: Managed equilibrium where North Island generation and price both increase



Source: NERA analysis.

[35] Preliminary Decision, p. iii-iv.

43. This figure illustrates that if South Island generators raise their offer curve to the point that the demand for exports is below the capacity of the HVDC:

    a. There will be a single price across both the North and the South Island,[36] determined by the intersection of the "managed" South Island offer curve and the North Island supply curve.

    b. Raising the South Island price above the constrained level has the effect of transferring some of the congestion rental to South Island generators (represented by the dashed purple, which is subset of the shaded purple area in Figure 2.4).

    c. Less generation will be exported from the South Island to the North Island (*SI exports (managed) < SI exports (constrained))*.

    d. In place of this forgone South Island generation, more expensive North Island generation must be dispatched (with the incremental North Island generation equal to *NI gen (managed) – NI gen (constrained)),* which raises total system costs.

    e. This results in a higher national price than the price that would occur in the North Island if the constraint was not managed (i.e. $P^{NI,managed} > P^{NI, constrained}$).

44. However, this diagram does come with some material caveats. In particular, the linear supply curve we draw implies that the marginal unit of generation in the North Island is more expensive in the managed scenario, whereas the supply curve could be flat over the relevant range (i.e., the incremental generation that is dispatched in place of the withheld South Island hydro may simply be more generation from the same plant that would have been marginal had the constraint bound). If this were the case, price in the North Island would not actually rise when additional North Island generation occurs in place of South Island generation. In addition, the level and slopes of the relevant supply curves have been deliberately chosen to illustrate the Authority's description of the outcome. We understand whether this is what actually happened is a point that is disputed by Meridian and we have not conducted our own modelling of the events during December 2019.

45. We also note that it is possible for offers to be used such that price separation does not occur, but the North Island price does not rise above the constrained level and the pattern of dispatch does not change. This scenario is demonstrated in Figure 3.2 below.

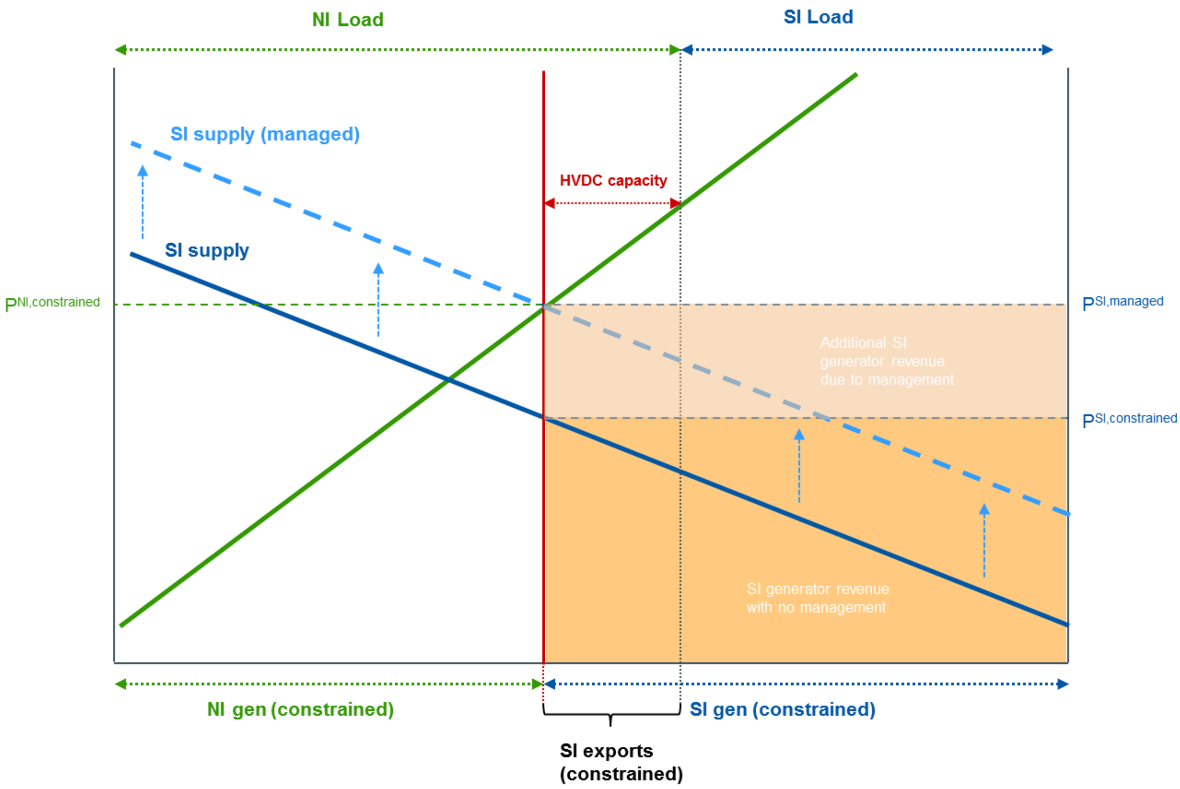
46. In this scenario, South Island generators raise their offers until the point at which the South Island offer curve, the North Island supply curve and the HVDC constraint line all intersect. In this scenario, the HVDC flows at full capacity, there is a single national price and the pattern of generation does not change relative to the situation if offers were not managed. Therefore, total system costs (from a short run dispatch perspective) do not change. This behaviour therefore has no impact on short-run productive efficiency.[37]

47. While using offers to manage constraints may impact on system costs and allocative efficiency (as well as the nodal price signals), the main effect is actually a transfer to generators from holders of FTRs and the parties entitled to receive LCE surplus and load. This would be reversing the value transfer that occurs when the additional unit of generation "flicks the switch" and causes the constraint to bind (as described above).

[36] This diagram effectively assumes there are only two nodes and ignores losses for simplicity of exposition.

[37] To the extent that load is inelastic in the short run (as is implicitly assumed in these graphs) there is also no effect on short run allocative efficiency.

Figure 3.2: Managed equilibrium with no North Island price effect or change in total system costs



Source: NERA analysis.

4. Efficiency of using physical offers to manage constraint risk

48. The Authority finds that Meridian's rationale was to avoid an HVDC constraint, and that this is not appropriate.[38] For example, at 12.26, the Authority states:

> *The Authority does not agree that Meridian should use offers to manage transmission constraints. This offer behaviour has a significant impact on the prices that end consumers pay and distorts prices as set out in Section 8.*

49. Other submitters responding to the Authority's preliminary decision have characterised Meridian's behaviour as an exercise of market power.[39] However, the Authority does not appear to be claiming there was a naked withholding of capacity to generate market power rents. Rather, the Authority appears to acknowledge that there was a risk management rationale.

50. As noted in section 3 above, using offers to manage price risk may reverse a value transfer away from generators that are upstream of the constraint. As discussed in section 2, in an energy-only market, generators need to recover their costs through the unit price they receive for their generation. A relevant consideration when assessing the use of offers to manage constraints, and the implications of an effective ban on this behaviour, is what would occur if the congestion rental is transferred away from generators. For example:

    a. Generators in one location may become reticent to retail or offer hedges in another location if they are unable to manage the price risk between those locations; and

    b. In the absence of evidence that generators are earning excessive profits,[40] this money would need to be "found" elsewhere if generators are to continue to recover their costs and invest.

51. As discussed above, the design of the NZEM involves exposing participants to constraint risk and allowing them to purchase FTRs to help manage that risk. The behaviour the Authority is objecting to is using physical offers to manage constraint risk. The counterfactual therefore appears to be that Meridian should have purchased FTRs to hedge the risk of price separation and then offered its capacity at a much lower price, or simply borne the risk. This is the explicit position the Authority quotes from its previous UTS investigation, at 12.28 of the preliminary decision:

> *The Board's view is that Meridian used its pivotal position to cover its unhedged risk on 2 June 2016, which essentially resulted in the cost of the risk being met by other parties. The high standard of trading conduct provisions were introduced to improve the efficiency of prices in pivotal supplier situations and the Board would have expected Meridian to have adopted more responsible trading behaviour, either by covering its risk using other available risk management products or bearing the cost of the risk if it eventuates.*

52. It is certainly clear that using offers to manage transmission constraints is likely to have an effect on prices – this is of course why it is a risk management tool. Whether that is necessarily "bad" depends on:

    a. The frequency, length and magnitude of the events. Infrequent, short use of offers in circumstances where price separation would not be material are unlikely to significantly affect end consumer prices (particularly given the existence of physical and financial hedges, as the Authority notes (e.g., at 14.21) or undermine the signalling effect of nodal prices.

---

[38] See, e.g., Preliminary Decision, paras 12.25-12.26.

[39] See, Haast, OJI, and Independent Retailers, *Response to UTS preliminary decision*, 18 August 2020, p. 5.

[40] I.e., profits in excess of their cost of capital.

b. The predictability of the event being responded to. It may not be cost effective to buy a generic risk management product for unpredictable and high consequence events.

c. What the social costs under the counterfactual would be (e.g., a reticence by South Island generators to invest in North Island retail).

d. Whether withholding South Island generation to manage the transmission constraint results in more expensive generation being dispatched either in the short term (e.g., North Island gas is dispatched instead of the withheld South Island hydro) or medium term (e.g., North Island hydro is dispatched instead of South Island hydro, which reduces North Island storage and results in North Island gas being dispatched at some other time in place of hydro). Offers can theoretically be used in a way that does not materially alter the pattern of dispatch and therefore only results in transfers (see Figure 3.2).

e. The costs and benefits of alternative risk management tools.

53. On this latter point, all risk management techniques involve a cost, which will ultimately fall on customers. The most obvious alternative risk management technique is FTRs. As already discussed, FTRs are designed to enable market participants to manage basis risk arising from the New Zealand nodal market.

54. However, FTRs cannot be effectively used to manage every basis risk. Most obviously, FTRs only exist between a pre-defined set of "hubs" and therefore not all locational price risk can be hedged using FTRs. In the Authority's recent review of the FTR market in New Zealand, an inability to cover all locational price risk is identified as one of the issues in the FTR market (note that following this review, hubs were established at three additional nodes):[41]

> *Participants are unlikely to be able to cover all their locational price risk with FTRs because […] FTRs are currently available between five 'hubs', relating to nodes on the grid at Otahuhu, Haywards, Islington, Benmore and Invercargill. These five hubs were chosen on the basis that they would cover most locational price risks. However, there will be some residual risk for parties that are exposed to spot prices at other nodes.*

55. The Australian Energy Market Commission ("AEMC") is currently considering a set of reforms that would introduce LMP and FTRs into Australia's national electricity market ("NEM").[42] When discussing the drawbacks of not providing FTRs at every node in the system, the AEMC noted:[43]

> *Generators which are not located at the pre-defined locations are not able to manage all their basis risk. It therefore leaves market participants with the risk of any remaining price difference between their connection point and the pre-defined node(s), and limited means to manage this.*

56. In fact, the Authority itself acknowledges that use of offers is an appropriate risk management tool in the absence of FTRs.[44]

57. Furthermore, risk management gaps can exist where FTRs are available between a given set of nodes if the available FTRs are not a good match to the risk a particular generator/portfolio faces (e.g., because of the particular generation profile of the plant in question) or FTRs are scarce. In this regard we note that the Authority itself noted in the 2017 review of the FTR market that

[41] Electricity Authority, *Financial Transmission Rights development, Issues and Options paper*, 28 March 2017, para 4.22.

[42] Note that NERA is advising the AEMC on the costs and benefits introducing LMP and FTRs, but we have not provided advice the AEMC on the design of FTRs.

[43] Australian Energy Market Commission, *Interim Report, Transmission access reform: Updated technical specifications and cost-benefit analysis*, section 3.6.2.

[44] Preliminary Decision, paras 13.12-13.15.

"[s]ome particular features of FTRs may limit how useful they are for some parties".[45] The same issue therefore exists along a spectrum even when FTRs are available.

58. If a generator is using physical offers to manage congestion risk when FTRs are available, this suggests that this is the cheaper option for that generator. This will be the case if:

    a. The available FTR products are not a good hedge for the generation profile of the plant in question; or

    b. The available FTRs are a good hedge for the plant in question, but because of its market position the generator can obtain the same risk management benefit more cheaply by withholding supply.

59. By arguing that using physical offers to manage constraint risk is inappropriate if an FTR exists, the Authority is essentially arguing that the first situation does not exist and that use of offers when FTRs are available constitutes some sort of abuse of a privileged position.

60. In this regard, we note the submissions of Genesis and Mercury argue that FTRs are not well suited for the type of unpredictable inflow situation faced by South Island generators in December 2019:

    a. Genesis states:[46]

       However, in Genesis's experience the existence of FTRs does not guarantee their availability at prices that make them an efficient risk management option in real time.

       This is particularly the case where unpredictable events are occurring at short notice, as was the case during the December 2019 flooding event.

    b. Mercury states:[47]

       The inability to perfectly hedge all price and basis risk through financial instruments means the use of physical market offers to manage transmission constraints is an important element of risk management for participants. This is particularly the case in response to infrequent, short duration market events which are unable to be hedged in real-time. For example, a large consumer with spot exposure can hedge some or all of its load with financial products, and always retains the ability to use physical assets (shut off some or all of its processes) to manage its risks.

61. Meridian, Genesis and Mercury make a variety of other points about the limits of FTRs, including (respectively) that they are coarse, crowded out by non-physical participants and are subject to scaling following revenue inadequacy.[48]

62. Meridian makes a similar statement to those made by Genesis and Mercury in relation to FTRs not fully covering the risks Meridian is exposed to, and also notes generators have made significant investments in making their operations flexible in order of provide a physical hedge:[49]

    As an aside the Authority's views on generators' offers to manage transmission constraints fail to recognise the significant investments made by generators (for example in plant, people, resource consents, and health and safety) to provide a physical hedge to manage volatile spot market risks. Meridian believes that requiring higher levels of hedge cover as an alternative to allowing participants to utilise their physical generation assets will drive up costs to consumers and significantly reduce the appetite for retail competition in areas of high basis risk.

[45] Electricity Authority, *Financial Transmission Rights development, Issues and Options paper*, 28 March 2017, para 4.1.

[46] Genesis Energy, *Re: Consultation on UTS preliminary decision*, 18 August 2020 ("Genesis submission"), paras 33-34.

[47] Mercury, *Submission on Preliminary Decision*, 18 August 2020 ("Mercury submission"), p.2.

[48] Meridian submission, p. 21; Genesis submission, para 37; Mercury submission, p. 2.

[49] Meridian submission, footnote 56.

> *Meridian does use risk management products to manage locational price risks. However, the risk management products available in the hedge market, including those in the financial transmission rights ("FTR"), Australian Securities Exchange ("ASX"), and Over the Counter ("OTC") markets are not always sufficient in their range and scope to cover locational price risks of the kinds Meridian experiences. Meridian would also face additional costs to cover its risk in this way and those additional costs would inevitably be passed on to consumers.*

63. The point raised by Mercury that the demand side can respond physically to high prices raises an interesting counter example to the Authority's view on generators physically managing constraint risk. If a large load customer switches off its assets and this changes the identity of the marginal plant, and therefore the prices paid by the rest of the market and that customer for its remaining load, would this be undesirable behaviour? Or is this somehow distinguishable and therefore symmetric treatment is not required? As Meridian notes in the quote above, significant investments have been made by generators to enable flexibility in the physical operation of their plants, and the value of these investments will be reduced if the situations in which this flexibility can be used are constrained.

64. Each of the following factors can affect the efficacy of FTRs as a risk management technique:

    a. **The capacity scaling process prior to the auction results in a volume of FTRs being sold which is less than the physical capacity of the line:** In the 2019 post implementation review of the FTR market, the Authority noted that, "[a]nother reason that FTRs have not changed generator offer behaviour might be that insufficient FTRs are available to fully cover one's exposure."[50] This suggests generators might be using offers to manage constraints because there are not enough FTRs available to cover the risk participants are exposed to. As we now set out, the scaling process adopted by the FTR manager in order to ensure revenue adequacy means this is often the case.

    The FTR manager only sells FTRs equal to expected capacity of the grid over a given month, accounting for planned and unplanned outages. With a very granular (in a time sense) product, this would not be a problem. However, FTR contracts cover each trading period at the same level for an entire month. This means that under the current FTR market design, planned outages on one day in a month impacts the volume of FTRs available to hedge locational risk occurring other days in the month. As a simplified example, consider a situation where a line with 200MW is going to be completely offline for half of the month, but at full capacity for the other half of the month. In this situation, the FTR manager might sell 100MW of FTRs to account for the outage. On the days when the line is flowing, there would be 200MW of capacity but only 100MW of FTRs, meaning participants would be unable to hedge all locational price risk in that month using FTRs.

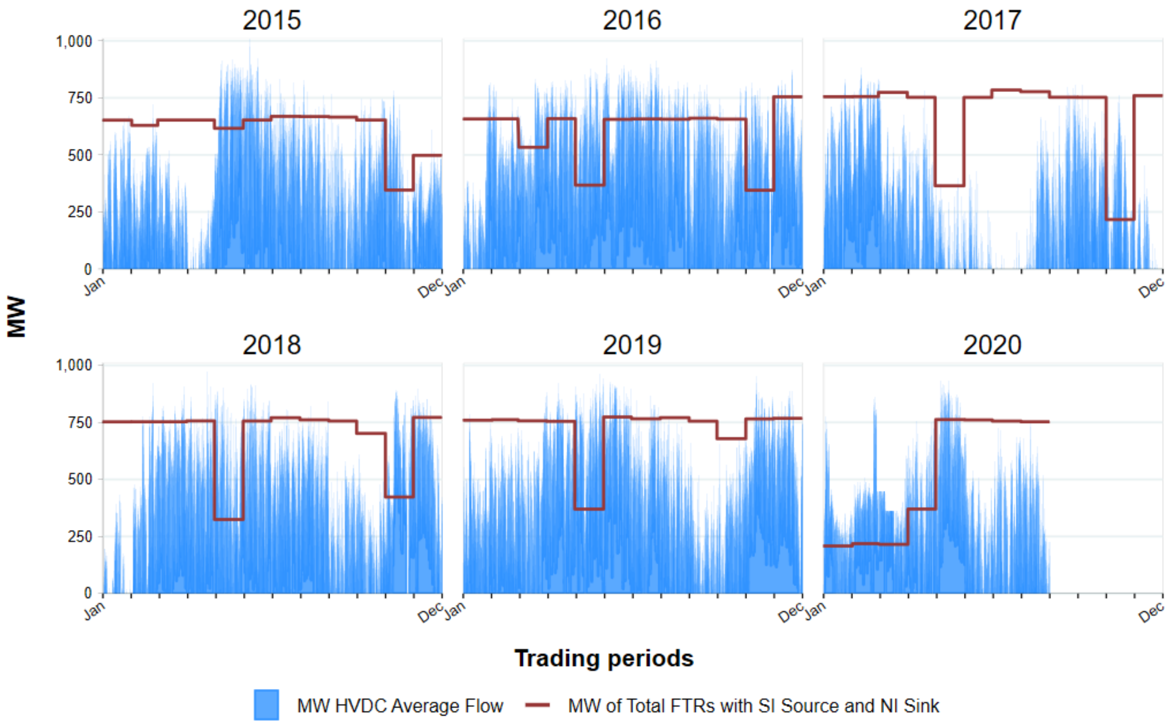
    In addition to capacity scaling for planned outages, the FTR manager makes a generic scaling assumption to the capacity of all assets on the FTR grid to account for the average impact of unplanned outages and electrical losses.[51] Assuming that information has been provided to the FTR manager on planned outages in the period, capacity for all assets are scaled by 83%.[52] Figure 4.1 and Figure 4.2 illustrate the impact of this point by comparing flows to the volume of FTRs sold for the HVDC.

[50] Electricity Authority, *Post implementation review of the FTR market: Report*, 14 November 2019, para 8.26

[51] This broad scaling also accounts for other planned outages that are not considered "relevant" in the determination of grid capacity (e.g., shorter duration). [Energy Market Services, *FTR Policy: FTR Grid and Auction Data*, 1 May 2019, section 4.3.]

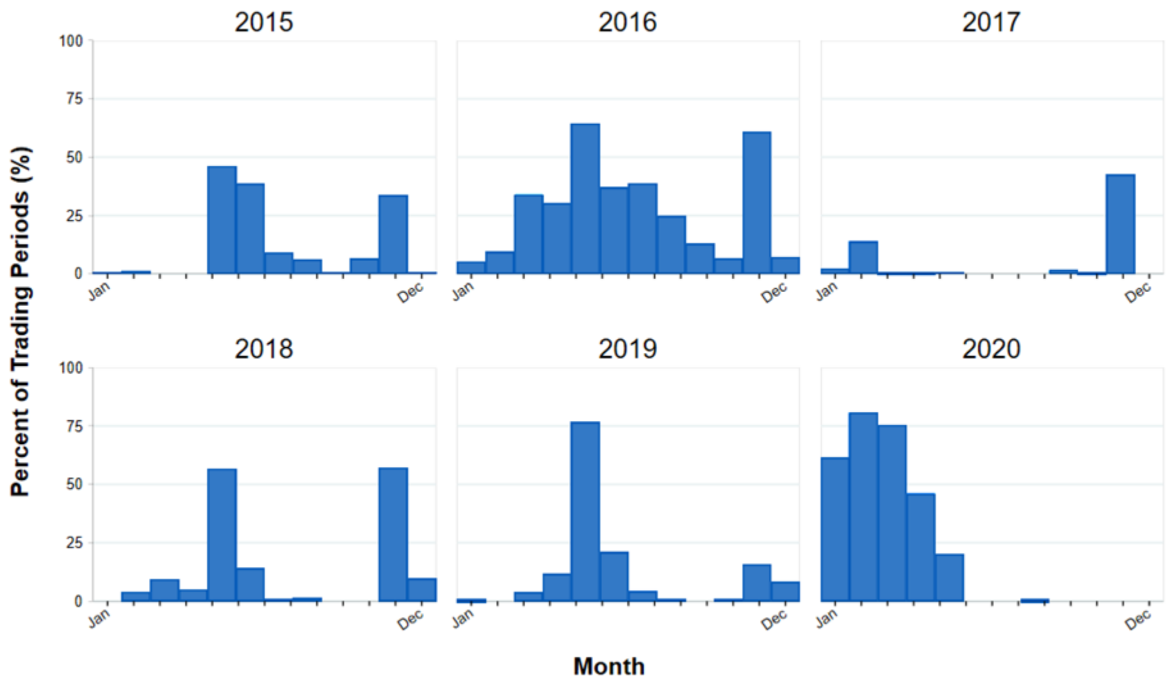
[52] Energy Market Services, *FTR Policy: FTR Grid and Auction Data*, 1 May 2019, section 4.3.

Figure 4.1: Northward HVDC flows vs volume northward FTRs (MW)



Source: NERA analysis of FTR Register data and EMI data.
Note: All FTRs which have a source in the South Island and a sink in the North Island are considered northward.

Figure 4.2: Percent of trading periods in which northward HVDC flows exceed volume of northward FTRs each month



Source: NERA analysis of FTR Register data and EMI data.
Note: All FTRs which have a source in the South Island and a sink in the North Island are considered northward.

b. **Continuous FTRs are a coarse hedge for plants that generate at certain times of day:** This point primarily relates to intermittent renewables that have a relatively predictable pattern of generation during certain times of day. For example, a solar plant can only generate during daylight hours, yet a continuous FTR hedges generation output (i.e., pays out) 24 hours a day regardless of whether the plant is generating. As the AEMC has noted, this creates an upside risk for FTR holders, such that they may under-procure FTRs:[53]

> *Some generators may choose to manage this upside risk by simply purchasing less financial transmission rights than their maximum capacity (in order to reduce their upfront costs). This outcome would be less than ideal, as it would necessarily introduce downside risk for the generator. That is, the financial transmission right may no longer be sufficient to optimally hedge against transmission congestion when the generator's preferred output is high.*

Put another way, a continuous FTR is an expensive way to hedge a solar plant. Having FTRs that only cover certain periods of the day would better match the generation profile of these plants. For this precise reason, the AEMC is proposing to introduce both continuous and "time of use" FTRs:[54]

> *Time of use rights may be particularly useful for some forms of variable renewable generators. For example, there is likely to be a high correlation between a solar generator's preferred output and the time of day when it needs to mitigate against transmission congestion.*
>
> *Further, this approach may result in positive consequences for other types of market participants. For example, we expect that solar generators will exclusively purchase time of use financial transmission rights that are active during daylight hours. This would allow additional FTRs (at a potentially lower price) to be released outside of these hours.*

Indeed, the Authority proposed introducing a "peak" FTR product that would only relate to certain times of the day in its most recent review of the FTR market in 2017, recognising this "would allow parties to more closely match their hedge cover to their load or generation profile".[55]

c. **Fixed volume FTRs are a coarse hedge for plants that have a variable generation profile:** This point is essentially an extension of the preceding point, which was that some plants predictably only generate at certain times of day. By contrast, some plants have output that is quite unpredictable. The FTRs available in New Zealand hedge a fixed capacity. For non-baseload generation, this type of contract is unlikely to be a good match for their output profile. For example, peaking plant and hydro storage may not always be fully dispatched.

This issue is particularly acute for intermittent renewables whose output depends on the weather, rather than the nameplate capacity of the plant in question or decisions by the plant operator. For example, on a particularly sunny/windy day output of solar/wind plant will increase, but the hedge provided by the FTR does not scale with that change in output.

The fixed volume and continuous nature of FTRs means that generators who hold an FTR will receive a payout during a constraint even if they do not generate (or generate at a level below that they have purchased FTRs for). For the same reasons as described above, continuous, fixed volume FTRs may lead some plants to under-hedge.

This is not to say some sort of variable FTR is necessarily desirable, as such a product would be complex to administer and design. Rather, we are highlighting that the available product

[53] Australian Energy Market Commission, *Technical specifications paper, Transmission access reform (COGATI)*, 26 March 2020, section 5.4.1.

[54] Australian Energy Market Commission, *Technical specifications paper, Transmission access reform (COGATI)*, 26 March 2020, section 5.4.2.

[55] Electricity Authority, *Financial Transmission Rights development, Issues and Options paper*, 28 March 2017, section 5.1(h).

has a mismatch with the output of certain plant types and therefore is not a perfect hedge. We also recognise that holding different plant types in a portfolio may result in a more consistent generation profile over time, which can mitigate the mismatch we have just described.

d. **Continuous FTRs are a coarse instrument for hedging infrequent and extreme events:** Continuous instruments that pay out in the event of *any* price separation may be an expensive instrument to hedge against unpredictable (with respect to their timing, rather than occurrence) and extreme events that cause a large degree of price separation. Risks of this type are ones that participants essentially want to purchase insurance against – for example, using a "cap" contract in the spot market, which only pays out when prices are above a certain level.[56] Such contracts do not currently exist for locational price risk, which leaves participants to either bear this risk, purchase continuous FTRs or use offers to hedge this risk.

e. **Continuous FTRs are a coarse hedge for infrequent and short duration events:** Similar to the previous point**,** events that are unpredictable (again with respect to their timing rather than occurrence) and short duration and, therefore, of relatively low consequence are expensive to hedge using continuous FTRs. Unlike for extreme events, it is difficult to write contracts targeted at these types of events. It for this reason that, for example, an owner might insure her car or other high-value personal items against theft (a high consequence event) but lower-value items may remain uninsured and instead the owner may take mitigating action to prevent the risk from occurring.

f. **Non-physical participants may increase the efficiency of FTR pricing, but this could crowd out physical participants:** Allowing non-physical participants to purchase FTRs should make the auction more efficient and increase the likelihood that FTRs trade at fair value. However, it may also crowd out generators who need these contracts (of which there is a fixed quantity available) to manage risk.[57]

The Authority recently considered expanding the FTR market to allow Australian participants to trade FTRs (in effect, further broadening the market to include more non-physical participants). In its decision following this 2017 review of the FTR market, the Authority "recognised the limited supply of FTRs, and that high levels of proprietary traders could make it more difficult to trade these for hedging purposes"[58] and that "existing FTR market participants are unlikely to benefit from broader participation".[59]

g. **A lack of firmness can leave residual constraint risk for FTR holders:** As described at paragraph 40, FTR payments are subject to scaling if LCE and auction revenue is not sufficient. Revenue inadequacy should only occur in the event of an unusual unplanned outage, because the capacity scaling of the FTR grid (i.e., the amount of FTRs offered relative to the transmission grid capacity) takes into account the average effect of unplanned and planned outages and electrical losses.[60] Even in this situation, the use of both settlement residue and the auction revenue to back FTR payments suggests that the risk of this occurring is relatively low. Indeed, the FTR manager has a revenue adequacy objective that states revenue inadequacy should only occur one month in 12, and the FTR manager must review

[56] Cap contracts are offered by the ASX in Australia and we understand that the ASX has been exploring introducing them in New Zealand. See, e.g., https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/market-insights/hedge-market-breaks-records/. We understand that Contact has offered OTC cap contracts before, but counterparties have not taken them up.

[57] For example, if non-physical participants form a different view on the likelihood of a constraint arising, they may be willing to pay more for the FTR than a generator that takes a different view.

[58] Electricity Authority, *FTR Enhancements, Decision Paper*, 24 April 2018, para 4.60.

[59] Electricity Authority, *FTR Enhancements, Decision Paper*, 24 April 2018, para 4.73.

[60] Energy Market Services, *FTR Policy: FTR Grid and Auction Data*, 1 May 2019, section 4.3.

the FTR policy if revenue inadequacy occurs in a third month of any rolling 12-month period or is less than 80% in any single month.[61] We understand that since the FTR market was introduced in June 2013, there have only been two months where revenue inadequacy occurred.[62] The Authority also recently initiated a consultation that will have the effect of using the LCE generated on parts of the grid that do not have FTRs to back the pay-outs of FTRs on other parts of the grid.[63] This should make FTRs firmer.

65. In summary, under the current market arrangements and grid, FTRs are not a comprehensive tool to manage all locational risks. In particular:

    a. The hub model and scaling of the volume of FTRs sold in the auction to something less than the physical capacity of the line in question can leave participants exposed to locational price risk; and

    b. Continuous FTRs covering a fixed volume for all dispatch intervals are a coarse hedge for:

        i. Irregular and short or high consequence events;

        ii. Plant with variable output and/or that only generate at certain times of the day.

66. Therefore, the existing FTR regime does not enable comprehensive management of all locational price risk. Given this, proscription of physical management of this risk without sufficient analysis of the full costs and benefits could have unintended consequences and be inefficient. Leaving generators with an unhedgable[64] risk may result in less investment (e.g., in retail expansion) or distorted investment if the only option to manage this risk is to locate generation away from the potential constraint.

67. These factors would of course need to be balanced against any distortionary effects of using offers (such as supressing nodal pricing signals), but that is not the analysis the Authority has conducted. We agree with the suggestions that if the Authority views this behaviour as problematic and believes a market-wide change is necessary, a UTS investigation is not the appropriate forum and instead the behaviour should be reviewed through a code change process, which would consider the full costs and benefits of eliminating such behaviour.[65] As part of such a process the Authority could also consider whether further changes to the FTR market might be desirable.

[61] Energy Market Services, *FTR Allocation Plan 2018*, sections 4.8-4.9.

[62] In the first occurrence in November 2018, 90% of LCE was allocated to FTR payments which were ultimately scaled down by 16%. The second occurrence in January 2019 had 100% of LCE allocated to FTR payments, and payments were scaled down by just 3%. [Electricity Authority, *Post implementation review of the FTR market: Report*, 14 November 2019, para 6.9, section 2.8-2.11; Energy Market Services, *FTR Manager Monthly Report*, December 2018; Energy Market Services, *FTR Manager Monthly Report*, February 2019.]

[63] Electricity Authority, *Removing requirement for FTR manager to calculate the amount of LCE to be applied to FTRs, Revocation of Schedule 14.3, Consultation paper*, 18 August 2020.

[64] In an economic sense.

[65] See, e.g., Meridian submission, p. 63-65; Contact submission, p. 5; Brattle Report, para 41.

Qualifications, assumptions, and limiting conditions

This report is for the exclusive use of the NERA Economic Consulting client named herein. This report is not intended for general circulation or publication, nor is it to be reproduced, quoted, or distributed for any purpose without the prior written permission of NERA Economic Consulting. There are no third-party beneficiaries with respect to this report, and NERA Economic Consulting does not accept any liability to any third party.

Information furnished by others, upon which all or portions of this report are based, is believed to be reliable but has not been independently verified, unless otherwise expressly indicated. Public information and industry and statistical data are from sources we deem to be reliable; however, we make no representation as to the accuracy or completeness of such information. The findings contained in this report may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. NERA Economic Consulting accepts no responsibility for actual results or future events.

The opinions expressed in this report are valid only for the purpose stated herein and as of the date of this report. No obligation is assumed to revise this report to reflect changes, events, or conditions, which occur subsequent to the date hereof.

All decisions in connection with the implementation or use of advice or recommendations contained in this report are the sole responsibility of the client. This report does not represent investment advice nor does it provide an opinion regarding the fairness of any transaction to any and all parties. In addition, this report does not represent legal, medical, accounting, safety, or other specialized advice. For any such advice, NERA Economic Consulting recommends seeking and obtaining advice from a qualified professional.

NERA Economic Consulting
Level 18
151 Queen Street
Auckland 1010
New Zealand