FTR Code amendment proposal consultation

Summary of submissions

18 September 2012

Market Design

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Contents

Tables

Executive summary

This paper provides responses to submissions on the *Code amendment paper* – 'FTR Code amendment proposals. Eight parties provided submissions in response to the Code amendment paper.

The paper summarises the submissions received and identifies and discusses substantive points and key themes raised by submitters.

1 Introduction and purpose of this report

1.1 In August 2011, the Electricity Authority (Authority) *Gazetted* changes to the Electricity Industry Participation Code 2010 (Code) to allow for the introduction of a financial transmission right (FTR) between Otahuhu and Benmore. The introduction of the FTR market will provide wholesale market participants with a mechanism to help manage their locational price risks, as required under section 42 of the Electricity Industry Act 2010.

1.2 In April 2012, the Authority announced that Energy Market Services (EMS) had been appointed to the role of FTR manager, with a start date of 1 May 2013 for the FTR market.

1.3 In preparation for the start of the FTR market, EMS and NZX, as clearing manager for the FTR market, sought further clarification on a number of implementation requirements. These were received by the Authority in the form of Code amendment proposals.

1.4 On 3 July 2012, the Authority released a consultation paper (Consultation Paper) entitled "FTR Code amendment proposals". The Consultation Paper outlined the proposed changes to the Code as well as alternative options for consideration. The Authority's preferred approach, which was reached with input from the locational price risk technical group, was outlined within the paper.

1.5 In addition, a number of proposed minor Code amendments were also publicised in the Consultation Paper. The Authority invited feedback on the proposed Code amendments and minor Code amendments by 5pm Monday 30 July 2012. The eight parties that provided submissions are listed below in Table 1.

Table 1 List of submitters

Number	Submitter
1	Contact Energy
2	Energy Market Services
3	Electric Power Optimization Centre (EPOC)
4	Genesis Energy
5	Meridian Energy
6	Mighty River Power
7	Transpower
8	TrustPower

Source: Electricity Authority

1.6 This paper summarises the submissions received and where appropriate responds to specific comments from submissions. The paper also outlines the outcomes and decisions on the Code amendments following consideration of the submissions.

2 Submission overview

2.1 An overview of submitter's responses is provided below in Table 2. In general the majority of submitters supported the Authority's proposals, with the exception of question 2, the priority given to parties when scaling is required as a result of a participant default. The Authority's proposal was to scale residual loss and constraint excess (paid to grid owners) and other FTR participants in equal priority. Several submitters disagreed with this approach with some suggesting FTR participants should be scaled first and one party submitting that the residual loss and constraint excess should be scaled first.

2.2 Electric Power Optimization Centre (EPOC) disagreed with the Authority's proposal to use only balanced injection patterns for schedule 14.6. All other submissions were in favour of this proposal.

2.3 There was also some disagreement with the Authority's proposed minor Code amendments. These were around clarifying the timing for an assignment and using the term "assignment" in reference to back to back deals for FTRs.

2.4 A number of other suggestions and comments were received from submitters on other improvements that can be made. These are discussed in more detail in section 3.

Table 2 Summary of responses

		Contact Energy	EMS	EPOC	Genesis Energy	Meridian Energy	Mighty River Power	Transpower	TrustPower
Q1	Do you agree with the proposal to scale FTR hedge values to manage reveune adequacy?	green	green	blue	green	green	green	blue	green
Q2	Do you agree with the proposal to give equal priority to grid owners and FTR participants for payments from the FTR account in the event of default?	green	red	blue	green	red	red	red	green
Q3	Do you agree that payer and payee invoices would set out values netted at the registered FTR level	green	green	blue	green	green	green	blue	green
Q4	Do you agree with the proposal to remove the requirement from clause 14.36(3) that the clearing manager issue invoices within 2 business days of delayed final prices being published?	green	green	blue	green	green	green	blue	green
Q5	Do you agree with the proposal to only use balanced injection patterns for schedule 14.6 calculations?	green	green	red	green	green	green	blue	green
Minor amendments	Terminology for FTR-related payments	blue	blue	blue	blue	blue	blue	blue	blue
Minor amendments	Clarify obligation to provide information about assignments	blue	red	blue	red	blue	blue	blue	blue
Minor amendments	Clarify timing of assignment difference payments to the clearing manager	blue	red	blue	blue	blue	blue	blue	blue
Minor amendments	Additional minor Code change to schedule 14.6	blue	blue	blue	blue	blue	blue	blue	blue

KEY	
green	Respondent supports proposal
red	Respondent does not support proposal
blue	No response or indifferent to proposal

Source: Electricity Authority

3 Support for majority of Code amendment proposals

3.1 The Consultation Paper sought comments on a number of proposals relating to arrangements for FTRs. This section identifies each of the proposals from the Consultation paper, the Authority's proposed solution (as outlined in the Consultation Paper), the feedback from submissions and the Authority's decision.

Scaling for revenue adequacy

3.2 Arrangements for scaling back FTR-related payments for revenue inadequacy are ambiguous and may lead to inefficient outcomes. The proposal was that, in the case of revenue inadequacy, FTR Hedge Values (whether they are positive or negative) will be scaled back on a pro rata basis.

Table 3 Question 1

Question	Response
Do you agree with the proposal to scale FTR Hedge Values (positive or negative) to manage revenue inadequacy?	Contact Energy, EMS, Genesis Energy, Meridian Energy, Mighty River Power and TrustPower all agreed with the proposal. EMS noted *"We expect this will lead to a significantly more efficient market"*. There were no submissions opposed to the proposal.

Source: Electricity Authority

3.3 All submitters agreed with this proposal and no information was raised that suggests the proposal is unsuitable. The Authority concludes that the original assessment of the options (including the cost benefit analysis underpinning the proposal) was supported. Accordingly, the Code amendment will be made as outlined in the Consultation Paper.

Priorities for default short-payments

3.4 Related arrangements for scaling back FTR-related payments to payees following a settlement default by a payer are also unclear. It was proposed that, in the event that a settlement default causes a need for shortfall payments from the FTR account, all payments of residual loss and constraint excess to grid owners, and all payments on FTR participants' payee invoices, should be scaled back with equal priority.

Table 4 Question 2

Question	Response
In the event of a shortfall of funds into the FTR account arising from a payer default, do you	Contact Energy, Genesis Energy and TrustPower all agreed with the proposal.

Question	Response
agree with the proposal to give payments from the FTR account to grid owners the same priority as payments to FTR participants?	Genesis Energy stated *“We consider that, in this situation, equal scaling is the fairest distribution of risk to both FTR participants and the grid owner”*. TrustPower said *“FTRs are, by definition, the financial purchase or grid revenue rights, and holders are therefore entitled to the same treatment as grid owners”*. EMS, Transpower and Meridian Energy all opposed the proposal and submitted that grid owners should have priority over payments. Meridian commented that *“we consider that the most efficient market design would see those parties who are able to realise the benefits of the FTR market (i.e. FTR participants) also bearing the risk of participant default”*. Transpower stated *“We do not agree that there are no strong reasons to give the Grid Owner a higher priority than FTR participants”.* Mighty River Power also opposed the Authority’s proposal. However, it submitted that FTR participants should have priority and be paid before grid owners. Mighty River Power also submitted that any LCE should be retained to fund any future revenue shortfalls which in turn would increase the ability to offer more FTRs at auction.

Source: Electricity Authority

3.5 There were mixed submissions on the priority of payments from the FTR account in the event of FTR payer default at settlement. If this occurred there may be insufficient funds in the FTR account to fully pay out all FTR holders and return the residual loss and constraint excess[1] to the grid owner. Scaling to one or both of these parties would be required. However, the current Code is unclear on who should get priority over the available funds.

3.6 The consultation paper outlined three options:

(a) grid owner has priority for payment;

(b) equal priority to grid owner and FTR holders; or

(c) FTR holders have priority for payment.

1 The residual loss and constraint excess is the surplus loss and constraint excess taken but not required to fund FTRs plus the auction revenue. Residual loss and constraint excess is paid to the grid owner. Prior to settlement the clearing manger calculates the amount of loss and constraint excess to retain to fund FTRs and issues the grid owner with an invoice listing the amount of residual loss and constraint excess they will receive.

3.7 The Authority proposed option (b), equal priority, on the basis of advice from its Locational Price Risk Technical Group (LPRTG) that there were no strong reasons to give the grid owner higher or lower priority than FTR participants.

3.8 Due to the mixed response in the submissions, further advice was sought from the LPRTG at its meeting on 15 August 2012. The LPRTG was unable to reach a consensus on who should have priority over payments. Member's views were split between placing the risk on to parties who were considered to be best able to manage the risk (FTR participants) and the competition benefits for those that trade FTRs (FTR participants), which would be promoted by giving FTR holders priority. The LPRTG also advised the Authority to base its decision on a principles based approach.

3.9 Table 5 assesses the three options against the Authority's Code amendment principles as outlined in the Authority's Consultation charter.

Table 5 Assessment against the Authority's Code amendment principles

Code amendment principle	Comment
Principle 1 - Lawfulness	All the options considered in the proposal are lawful and consistent with the Act.
Principle 2 – Clearly identified efficiency gain or market or regulatory failure	The three options proposed are a response to problems created by the existing Code, namely a lack of clarity in arrangements for default scaling. As a result all three options will improve the efficiency of the electricity industry for the long-term benefit of consumers. This is relative to the counter-factual, under which there is the potential for dispute following a default as to whether scaling of payments from the FTR account was carried out lawfully.
Principle 3 – Quantitative assessment	It is not possible with any accuracy to make a quantitative assessment of the benefits of each of the three options because the impact on competition and efficiency (efficiency effects of who bears the risks) cannot be quantified. A qualitative assessment has been carried out in Table 6.
Principles 4-9	The tie-breaker principles are not required because the qualitative assessment indicates a preferred approach.

Source: Electricity Authority

3.10 A qualitative assessment of the costs and benefits of giving priority of payments to the grid owner, *vis a vis* giving priority of payments to the FTR participants is described below in Table 6. The costs and benefits of the intermediate option of giving equal priority to grid owner and FTR holders are not assessed because this is a hybrid option where the costs and benefits would lie between those discussed below.

Table 6 Qualitative assessment of the two options

Statutory objective criteria	**Impact of option (a): priority for payments to the grid owner**	**Impact of option (c): priority for payments to FTR participants**
Competition	If FTR participants carried the risk of FTR default payments for FTRs it would reflect efficient price discovery and valuation. FTR market bids would reflect the risk that payments may be scaled due to a default on settlement. However, efficient price discovery would see a decrease in auction revenue reflected by lower bids for FTRs. This would decrease the value of an FTR and reduce competition in the FTR market. Ultimately the hedging properties of an FTR will be decreased if they are less firm, which will have an adverse impact on competition.	This would increase the firmness of FTRs, as the residual loss and constraint excess would be scaled first. A firmer product would improve the hedging properties provided by FTRs, improving the ability of FTRs to support retail and generator competition. A firmer product would also be more valuable to participants and should increase competition for FTRs. This would result in a more active FTR market with increased bidding, which would increase auction revenue and support the firmness of FTRs.
Reliability	Not applicable	FTRs offer a hedge mechanism for parties to manage their locational price risk. The firmer the product the better. Generally, parties who are better hedged against their risk are incentivised to manage their generation and load portfolios prudently.
Efficiency	Giving priority to the grid owner would put the risk onto FTR participants and ensure an incentive to efficiently manage robust prudential requirements. However, the incentives on participants to support robust prudential requirements are likely to reflect the competitive positions in the market. Moreover, the ability of an individual FTR holder (in a blind pool) to reduce the risk of default by another FTR holder is very limited. This is appropriate as it ensures each holder already has strong incentives for robust risk management of default risk.	Any increase in auction revenue will increase the average residual loss and constraint excess that is paid to the grid owner. Recipients of the residual loss and constraint excess (transmission customers) would accordingly see an increase in their rebate. This approach would also support the underlying design principle for the FTR market that loss and constraint excess is used to fund FTRs. In the event of a default, giving priority to FTR participants would maximise the use of the loss and constraint excess as a means of firming FTRs.

Source: Electricity Authority

3.11 Whilst the view of some submitters is that the risk should be borne by the parties best able to manage it (FTR participants) and payment priority should be given to the grid owner, the Authority does not consider this to be a strong argument. The gains from this approach are marginal as any individual FTR holder has very limited levers to reduce the risk of default by another FTR holder. The Authority consider that the qualitative analysis shows greater gains can be achieved from the competition benefits of adopting option (c) and providing priority for payment to FTR participants. In addition, small reliability and efficiency gains can also be realised with option (c).

3.12 Therefore, based on a revised cost benefit analysis, the Authority has selected option (c), reversing the proposal outlined in consultation, and will give priority to FTR participants for payments from the FTR account in the event of a settlement default.

Invoicing provisions

3.13 Requirements for invoicing FTR-related payments on payer and payee invoices are unclear. The proposal was to require net FTR values (FTR Hedge Value minus FTR Acquisition Cost) for each FTR to be included on payee invoices when they are positive and on payer invoices when they are negative.

Table 7 Question 3

Do you agree that payee invoices should contain: a) for each FTR held by the payee, the net of the FTR Hedge Value minus the FTR Acquisition Cost, where that net value is positive, and b) for each assignment for which the payee is the assignor and for which the Assignment Difference Payment is negative, the absolute value of the Assignment Difference Payment? In this case, payer invoices would contain: • for each FTR held by the payer, the net of the FTR Acquisition Cost minus the FTR Hedge Value, where that net value is positive, and • for each assignment for which the payer is the assignor and for which the Assignment Difference Payment is positive, the Assignment Difference Payment.	Contact Energy, EMS, Genesis Energy, Meridian Energy, Mighty River Power and TrustPower all agreed with the proposal.

Source: Electricity Authority

3.14 All submitters agreed with this proposal and no information was raised that suggests the proposal is unsuitable. The Authority concludes that the original assessment of the options (including the cost benefit analysis underpinning the proposal) was supported. Accordingly, the Code amendment will be made as outlined in the Consultation Paper.

Invoicing when final pricing is delayed

3.15 When final pricing is substantially delayed for some trading periods, the Code requires the clearing manager to issue invoices within two business days of delayed final prices being published. It would be very expensive for the clearing manager to build systems to meet this requirement. It was proposed that the requirement be removed. This would allow the clearing manager and the Authority to negotiate appropriate systems to deal with these rare events.

Table 8 Question 4

Question	Response
Do you agree with the proposal to remove the requirement from clause 14.36(3) that the clearing manager issue invoices within 2 business days of delayed final prices being published? Note that this proposal would allow the clearing manager and the Authority to negotiate appropriate system features to help deal with invoicing following delays in final prices, with a view to later amendment of the Code.	Contact Energy, EMS, Genesis Energy, Meridian Energy, Mighty River Power and TrustPower all agreed with the proposal. Contact Energy commented *"In Contact's view this is a pragmatic approach to low risk, low probability events. As such, Contact is supportive of the approach outlined. Contact does not support costly systems being developed for the sole purpose of meeting a two day timeframe"*. There were no submissions opposed to the proposal.

Source: Electricity Authority

3.16 All submitters agreed with this proposal and no information was raised that suggests the proposal is unsuitable. The Authority concludes that the original assessment of the options (including the cost benefit analysis underpinning the proposal) was supported. Accordingly, the Code amendment will be made as outlined in the Consultation Paper.

3.17 The Authority intends to develop standard arrangements for invoicing when final prices are delayed for both the FTR market and the energy market. This is part of the improvements to existing spot pricing processes project currently on the Authority's work plan.

3.18 The Authority notes Meridian Energy's suggested changes to the Code in this area, which were to:

amend clause 14.36 to establish that the clearing manager must:

(a) act as soon as reasonably practical; and

(b) invoice and settle affected FTR amounts in parallel to any other affected transactions (e.g. wholesale market transactions); and

amend clause 14.73 to require the FTR manager to act as soon as reasonably practical in deriving the FTR rental excess to be retained by the clearing manager in event of final price delays.

3.19 Clause 14.73(2A) currently states that the FTR manager must advise the clearing manger of the FTR portion of the loss and constraint excess "…no later than 1600 hours on the 7^{th} business day of the month following the relevant billing period".

3.20 In its submission, EMS (the FTR manager), commented that it will not be able to meet this obligation in the event of a long delay in publication of final prices. EMS suggests a timeframe of 4 business days after publication of final prices is more appropriate.

3.21 The Authority notes these comments and will consider whether or not any amendments to the Code are required on a short term basis whilst analysis is carried out on the wider project developing Code provisions for invoicing in the event of a delay in final prices.

3.22 The Authority notes the comments made by TrustPower that invoicing for the FTR market should be aligned with the ASX24 operating rules, and will consider the comments as part of its consideration of possible Code amendments for delays in final pricing. TrustPower stated:

"Trading of FTRs will, no doubt, be hedged via the ASX market, and not aligning the payment structure of these two markets could leave a participant with non parallel payment structures in the event of delayed final prices"

Change to Schedule 14.6

3.23 When determining the amount of loss and constraint excess to allocate to supporting FTRs, the Code requires the FTR manager to use a methodology set out in Schedule 14.6. The FTR manager has notified the Authority that the methodology is not robust to some unusual situations that might arise. The proposal was that the methodology be amended to use balanced injection patterns (rather than unbalanced injection patterns) as an input. This will make the methodology more robust.

Table 9 Question 5

Question	Response
Do you agree with the proposal to only use balanced injection patterns for schedule 14.6 calculations?	Contact Energy, EMS, Genesis Energy, Meridian Energy, Mighty River Power and TrustPower all agreed with the proposal. EPOC opposed the proposal stating *"No, we do not agree. We show that in some circumstances the proposal can fail to deliver outcomes for which it is designed"*. EPOC also state *"We argue that this might fail to collect a sufficient amount of constraint and loss rental"*.

Source: Electricity Authority

3.24 The majority of submitters supported this proposal and hence the Authority's assessment of the options (including the cost benefit analysis) was also supported by the majority of submitters.

However, one submitter, EPOC, opposed the proposal. The Authority has given consideration to the submission and example provided by EPOC.

3.25 The example shows that, in extreme cases, calculating the rental split based on balanced injection patterns may collect significantly less rent than intended. In EPOC's example, zero rents are collected. Although the Authority notes that historical analysis suggests this is not a material issue. In reality the chance of getting exactly zero flow is extremely low. Should less rent be collected than intended it would likely result in scaling of FTR hedge value payments. However, the Authority considers it to be a more workable approach than the current drafting of Schedule 14.6.

3.26 Accordingly, the Authority consider there is no need to depart from the cost benefit analysis underpinning this proposal and the Code amendment as outlined in the consultation paper be made.

4 Disagreement with some of the proposed minor Code amendments

4.1 Of the four Code amendment proposals the Authority considers to be minor, comments were received on two.

4.2 There were no comments on the proposed new terminology or the additional amendment to Schedule 14.6 to correct a clause reference. The changes in terminology will be made as outlined in the consultation paper. The amendment relating to cross referencing in Schedule 14.6 was included in the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

4.3 The Authority proposed to amend the Code so that it was clear that parties are welcome to trade the cash flows associated with an FTR bilaterally, without providing information to the FTR manager (non-registered transactions). The Authority proposed adding "<u>and have that assignment registered by the **FTR manager**</u>," to clause 13.248(1) of the Code.

4.4 Both Genesis Energy and EMS submitted that this change would add further unnecessary confusion. They argue that the term "assignment" should only be used to define registered transactions, and that the proposed amendment would use the term "assignments" for both registered and non-registered transactions.

4.5 The Authority agrees with these submissions that the amendment could create more confusion than it would remove. Therefore, the Authority will not make this proposed minor Code amendment.

4.6 Finally, it was proposed that amendments would be made to clause 13.249(5) and the date field in Form 1 of Schedule 13.6 (the form used to assign an FTR to another party). Clause 13.249(5) refers to the billing period "in which the assignment took place". It was considered that the reference to "took place" could be confusing, and therefore it was proposed that "took place" be replaced with "was registered". In relation to the date field in Form 1 of Schedule 13.6, it was considered unclear whether the date field referred to the date the trade was agreed or the date the trade was registered. Therefore, a clarification was proposed stating that the date the trade was registered should be entered. EMS submitted these changes were unnecessary on the basis that the date that parties privately agree that they will submit an assignment application is not relevant to the operation of the assignment mechanism, and the operative date of an assignment is unambiguous. The Authority agrees with EMS. Therefore, these minor Code amendments will not be made.

5 Additional comments also received

5.1 Submitters also took the opportunity to provide the Authority with additional comments on FTR Code provisions. In particular Genesis Energy submitted that:

"Transparent price signals will also enable more accurate prudential calculations. The Clearing Manager has indicated that sufficient trading and disclosure of FTR prices will enable them to reconsider its use of more approximate instruments (such as modelling or reliance on ASX information) in their prudential methodology."

5.2 Genesis Energy suggested that the Code be amended to require disclosure of price when assigning FTRs using Form 1 in Schedule 13.6. The Authority notes that these comments are not in response to a specific question raised in this consultation but are in relation to the provisions for secondary trading. As a result the Authority will consider the comments made by Genesis Energy when considering the provisions for secondary trading.

5.3 Meridian Energy noted:

"the definitions of option and obligation FTRs set out in Part 1 implicitly assume a gross settlement system. To address this, the Authority could consider re-defining these terms with reference to Hedge Value rather than payment entitlements. [Footnote: For instance, a positive obligation FTR could be described as: (excluding the FTR acquisition cost) the Hedge Value of an FTR obligation will be positive when, for the FTR period, the difference between the price (calculated in accordance with the terms of the FTR) at the hub identified as hub B and the price at the hub identified as hub A in the FTR is positive.] This could then allow for the relevant clauses to be simplified using the FTR Hedge Value definition the Authority is proposing to incorporate. Alternatively, the Authority could cross-reference definitions incorporated into FTR policies rather than including separate definitions in the Code."

5.4 The Authority notes these comments but does not consider any changes are necessary at this time.