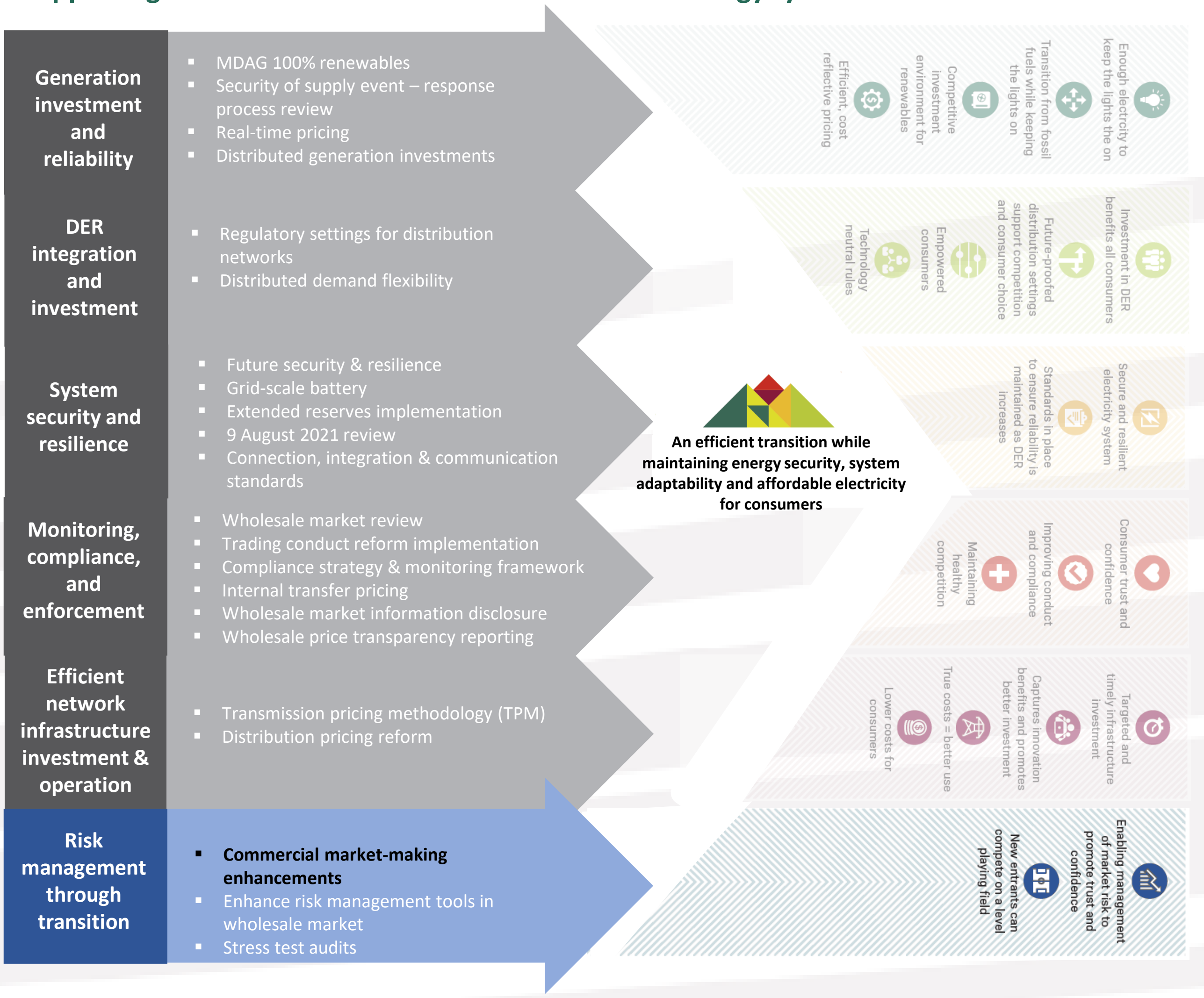
Hedge Market Enhancement: Commercial Market-Making Scheme

Commercial Market-Making Code Amendment

Decision Paper

26 July 2022

Supporting an efficient transition to a low emissions energy system



Executive summary

The exchange traded New Zealand electricity futures market performs two key functions; electricity market participants use it directly and indirectly to manage their spot price risk, and participants and other interested parties use the forward price curve the futures market creates to inform a wide range of investment and operational decisions. These market functions promote the long-term interests of consumers by enabling efficient decisions and fostering competition and transparency.

In August 2020, the Authority decided to introduce, as part of its *Market Making Enhancements*: *market-making project (HME),* an enduring market-making approach that enhances the then existing market-making arrangements while improving efficiency, trust and confidence in the market.

The Authority will be implementing the first iteration of this enhanced market-making arrangement on 1 September 2022. This involves introducing a new commercial market maker who will provide 20% of the total volume of market-making contracts, with the remaining 80% being provided by the existing regulated market makers.

The Authority has recently completed a robust two-stage procurement process for a commercial market maker. The Authority has also been consulting with industry participants, most recently in February 2022 on the proposed amendments to the Electricity Industry Participation Code 2010 (Code) that would set the service level parameters for both regulated and commercial market makers. The Authority has considered all submissions received and has decided to proceed with its proposal, with some key amendments based on feedback received.

This paper sets out the decision by the Authority to amend the Code to enable the introduction of a Commercial Market Maker and the outcome of the procurement process to select a commercial provider.

Contents

1. The Authority will amend the Code to introduce a commercial market maker

1.1. In August 2020[1] the Authority decided to pursue an enduring market-making approach that secured the benefits of the (then) current arrangements while enhancing efficiency, improving trust and confidence in the market, and facilitating a service-oriented approach.

1.2. The Authority's decision for the enduring market-making approach was to transition over a period of years, to a fully incentivised arrangement where market-making services are solely provided by commercial market makers.

1.3. To ensure the integrity of market-making services is maintained during this transition, the Authority decided the first iteration of the commercial scheme will appoint one or more commercial market makers to provide 20% of the total volume of market-making contracts. The remaining 80% will be provided by the existing regulated market makers (Contact, Genesis, Meridan and Mercury).[2]

1.4. To implement the first iteration of the August 2020 decision, the Authority has undertaken the following steps:

(a) amended the Code in April 2021 to include provisions for a mandatory market-making backstop requiring the four large generator-retailers to become regulated market makers under the Code;[3]

(b) secured funding for the commercial market-making scheme (Cabinet approved an ongoing annual increase for a maximum of $14.4m per annum from the financial year 2022/23);[4]

(c) consulted levy payers on increasing levy payments to fund the commercial market-making scheme;[5]

(d) undertook a robust two-stage procurement process to select a commercial market maker; and

(e) consulted stakeholders on proposed Code amendments in March 2022 to improve market performance and introduce the first iteration of the commercial market-making scheme.

1.5. This decision paper sets out the outcome from the procurement process for a commercial market-maker and the Code amendments required to enable the new service level parameters for both regulated and commercial market makers.

The Authority procured Bold Trading to be the commercial market maker

1.6. The Authority conducted a two-stage and robust procurement process to identify and procure a service provider.

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[1] The summary of the Authority's decision paper is available here: Decision summary on enduring market making approach — Electricity Authority (ea.govt.nz)

[2] Consultation paper: Hedge Market Enhancements: Commercial market making scheme Code Amendment Consultation paper, Electricity Authority, 2022. Available here: Hedge-Market-Enhancements-Commercial-market-making-scheme-Code-Amendment-Consultation-paper.pdf (ea.govt.nz)

[3] Consultation paper: Hedge Market Enhancement: Permanent market making backstop, Electricity Authority, 2020. Available here: https://www.ea.govt.nz/assets/dms-assets/27/Consultation-Paper-Hedge-Market-Enhancements-Permanent-market-making-backstop.pdf

[4] More information is available here: Commercial market-making scheme - increase to the Authority's appropriation — Electricity Authority

[5] Consultation paper: Levy Consultation: Commercial Market Making Scheme, Electricity Authority, 2021. Available here: Long-form report (ea.govt.nz)

1.7. The first stage was a Registration of Interest (ROI). The Authority invited local and international organisations interested in providing commercial market-making services to provide feedback on a proposed commercial market-making scheme. The ROI was open between 16 August and 24 September 2021, with the Authority receiving interest from six parties.

1.8. In December 2021, the Authority shortlisted four of these parties to participate in a Request for Proposal (RFP) as the second stage of the procurement process. The RFP stage was open between 15 February and 29 March 2022.

1.9. Based on the RFP submissions, which were evaluated against technical, commercial and policy criteria, the Authority selected Bold Market Making NZ Limited (Bold Trading) as its preferred commercial market-making service provider.

A Code amendment is required to set out the new service level parameters for market-making and enable a commercial provider

1.10. The Electricity Industry Participation Code 2010 (Code) sets out the requirements for the regulated market makers.

1.11. In February 2022, the Authority consulted stakeholders on a proposed Code amendment that set the following parameters for regulated market makers and commercial market-makers as part of an enduring market-making approach:

(a) total market-making volume of 12 MW per contract (with 2.4MW allocated to a commercial provider/s and 9.6MW allocated to regulated providers);

(b) spread between bid and offer prices of up to 3% (the existing requirement for regulated market makers);

(c) market-making exemptions of five days per rolling 20 trading days (compared to the existing arrangements of five days per calendar month); and

(d) inclusion of a refresh obligation (compared to existing requirement to provide all volume at once).

1.12. Having considered feedback by stakeholders, the Authority has decided to progress with the proposed Code amendments, with minor changes to some of the service level parameters, these are set out in Table 1.

Table 1: Service level parameters set out in the Code

Consulted service level parameters	Changes	Final service level parameters
Total market-making volume of **12 MW per contract** (with 2.4MW allocated to commercial provider/s and 9.6 MW allocated across the regulated providers)	Unchanged	Total market-making volume of **12 MW per contract** (with 2.4MW allocated to a commercial provider and 9.6 MW allocated across the regulated providers)
Spread between bid and offer prices of up-to **3%**	Unchanged	Spread between bid and offer prices of up-to **3%**
Market-making exemptions of **five days per rolling 20 trading days**	Unchanged	Market-making exemptions of **five days per rolling 20 trading days**
Inclusion of a mandatory **refresh obligation**	Changed	Adopting a **refresh option** will now be **voluntary** for all market makers

Volume and spread

1.13. Currently, each regulated market maker provides 3 MW of volume for each market made contract. Across the four existing market makers, this amounts to a total of 12 MW of volume available to buy or sell at a bid-ask spread of up to 3%.

1.14. The Authority consulted on a proposal to maintain the 3% spread and total 12 MW volume (allocating 2.4 MW for each regulated and commercial market maker) and has decided to retain this proposed volume.

1.15. Feedback largely supported the proposed volume and bid-ask spread. However, some submitters, such as Contact suggested the 3% bid-ask spread is too narrow for contracts at the front end of the futures curve, given its high volatility. Meridian also questioned whether the 12 MW of total volume would be available under the proposed refresh option.

1.16. A joint-submission by Electric Kiwi, Flick, Haast Energy, Pulse Energy and Vocus proposed using the commercial market maker as an opportunity to increase this volume by 3 MW to a total of 15 MW and expressed preference for the bid-ask spreads to be narrower.

1.17. Based on the feedback from the consultation process the Authority decided to retain the current total volume of 12MW, allocating 2.4MW to each market maker and retain the bid-offer spread at 3% which will apply to both regulated and commercial market makers.

Exemption period

1.18. The Authority has decided to retain the proposed exemption regime of five days per rolling 20-day trading period.

1.19. Stakeholders broadly agreed that the current exemption framework (five exemptions in a calendar month) is not efficient and tends to lead to reduced liquidity at the end of the month. Most stakeholder submissions were supportive of the proposed change. However, some of the regulated market makers (Genesis, Contact, and Meridian), while agreeing with the principle and reasoning behind the proposed change, highlighted the use of exemption days merely reflects the cost of market-making. Genesis proposed a regime of five exemption days per rolling 15-day trading period. In contrast, other stakeholders suggested reducing the number of exemption days from five to two, with Octopus Energy suggesting there should be no opt-outs. See Table 3 for stakeholder feedback that contributed to the decision on final service level parameters.

1.20. On balance, the Authority's decision to retain the five exemption days per rolling 20-day trading period will address the lack of trading resulting from the absence of market-making occurring at the end of each month under the current system, while also increasing market efficiency and allowing market-makers flexibility to manage their risk and reduce the cost of market-making.

Revised refresh option

1.21. The Authority decided to retain the refresh option, however, as a voluntary feature.

1.22. The refresh obligation was proposed during stakeholder consultation to address liquidity issues in the futures market and lack of robustness of the forward price curve due to instantaneous trading that was observed by the Authority.

1.23. Stakeholder feedback on the refresh option suggested this proposal would have the opposite effect through increasing market-making costs and reducing market efficiency and price discovery. Among the four regulated market-makers, Mercury supported the refresh option, but suggested it be targeted. Genesis and Contact similarly supported its intent but suggested a hybrid bid-ask spread would better address liquidity issues. Meridian however, strongly rejected the proposal believing it would reduce the volume of contracts available and increase market-making costs. emhTrade held a similar view to that of Meridian.

1.24. Following these concerns, the Authority undertook further analysis of trading data to establish which of these submissions held merit and required further consideration.

1.25. Based on this analysis, the Authority has decided to retain the refresh obligation, however, instead of it being mandatory, it will now be available to all market makers on a voluntary basis.

1.26. The decision for amending the refresh option to be voluntary, is on the basis that it provides flexibility for market makers who prefer to offer their full obligation volume in their first order, while also improving liquidity and efficiency in the market and not imposing additional costs or complexity. It allows market-making firms to determine their operating strategy in providing services without imposing the same solution on all firms.

1.27. The updated service level parameters are reflected in the Code (refer to **Appendix A**) alongside some other minor Code amendment suggestions by stakeholders, captured in Table 3 below.

The Authority has also updated existing processes for monitoring exemption use

1.28. Alongside the introduction of the new service level parameters, there is an additional amendment to the Code including new exemption monitoring processes that market makers will need to comply with.

1.29. As outlined above, market makers will have five exemptions in a rolling 20-day trading period. Outside of these exemptions, there are only two other permitted circumstances outlined in the Code under clause 13.236N(1)(a)(i) and (ii) where market makers are exempt from market-making. These provisions are there to protect market makers in specific situations if they are unable to meet market-making obligations.

1.30. The Code now requires market makers to inform the Authority as soon as practicable, but no later than 17:00 New Zealand Time on the same business day that exemptions and permitted circumstances is relied upon. This will be done through a market-making portal made available to all market makers. Market makers will also be able to monitor their compliance data and exemption use through the portal. Other market participants will continue to be able to access market-making data through EMI.

1.31. Further details and information on this portal will be made available to all market-makers ahead of the go-live date of 1 September 2022.

2. Market-making scheme changes will be implemented 1 September 2022

2.1. The first iteration of the commercial market-making scheme will be implemented 1 September 2022. This means Bold Trading will enter the market as the new commercial market-maker, and both the commercial and regulated market makers will be required to market-make under the new service level parameters as set out in the Code (for regulated market-makers) and the *'Agreement for the provision of Market-Making Services for the New Zealand Electricity Futures Market'* for the commercial market maker.

2.2. Leading up to the implementation date, the Authority will engage with the regulated market-makers (Contact, Genesis, Mercury and Meridian) to ensure each market maker understands their compliance requirements under the new amended service level parameters.

3. This proposal will be a net benefit to consumers

3.1. The introduction of a commercial market-making scheme is expected to be a net benefit to consumers because it will enhance the performance of the New Zealand electricity futures market, which:

(a) allows New Zealand electricity market participants to benefit from a robust and liquid forward price curve;

(b) allows those that trade in the ASX futures market to benefit from liquidity and price efficiency supported by market-making;

(c) allows for greater competition in the retail and generation markets; and

(d) this increased market information transparency, more robust forward price curve, and improved price efficiency, will increase market innovation and lead to greater consumer choice and price benefits.

3.2. Submissions by stakeholders provided mixed feedback on the Authority's cost benefit analysis (CBA):

(a) A joint submission by Electric Kiwi, Flick, Haast Energy, Pulse Energy and Vocus expressed support for the increase in the levy, only on the basis it funds a new commercial provider or if the Authority intends to increase the total volume above 12MW.[6]

(b) emhTrade disagreed with the Authority's stance that the refresh obligation could potentially be a significant improvement to levy payers, instead, suggesting it would result in an increase to the cost of market-making.

(c) Meridian did not agree with the Authority's CBA on the refresh obligation but did agree that there would be benefits to levy payers if the commercial provider is willing to provide a service with a refresh option at a reduced price.

(d) Contact Energy disagreed with Authority's CBA for the exemption regime, suggesting that instead of seeing a lower fee for market-making of at least $500,000 per annum as proposed by the Authority, that the exemption regime would result in additional market-making and resourcing costs which will exceed $500,00 per annum.

3.3. The cost concerns raised by some stakeholders with elements of the Authority's CBA analysis from the consultation process have been considered. As noted above, the Authority is adopting voluntary refresh option in place of it being mandatory. This will address the cost concerns of the refresh option that were noted by Meridian, Contact, and emhTrade, while still providing market makers with more options to manage their trades offs while market-making.

3.4. The Authority has updated the CBA, see **Appendix B**: Revised Cost Benefit Analysis, and considers that the CBA analysis undertaken to date indicates the Code amendments set out in **Appendix A**: Commercial market-making Code amendment, will result in a net positive benefit to consumers.

4. The Authority's decision has been informed by stakeholder engagement

4.1. The Authority held several rounds of formal engagement with stakeholders as it conducted its review of market-making arrangements, including formal consultation processes, bi-lateral meetings, and meetings with groups of stakeholders.

4.2. The most recent engagement was the consultation the Authority undertook between February and March 2022 on the proposed amendments to the Code that would set the service level parameters for both regulated and commercial market makers.

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[6] As noted earlier, the volume issue is out of scope for this consultation as it was decided previously by the Authority as part of the commercial market-making levy consultation - Long-form report (ea.govt.nz)

4.3. The Authority received submissions from 10 parties listed in Table 2 below.[7]

Table 2: List of submitters

Submitter	Category
Contact	Generator/retailer/market maker/trader
Genesis	Generator/retailer/market maker/trader
Mercury	Generator/retailer/market maker/trader
Meridian	Generator/retailer/market maker/trader
Nova	Generator/retailer/trader
Haast Trading, Electric Kiwi, Flick, Pulse and Vocus	Independent retailer/trader
Octopus Energy	Independent retailer
Bold Trading	Trader
emhTrade Markets	Trader
New Zealand Wind Energy Association	Industry association

5. The Authority has amended its proposal in response to stakeholder submissions

5.1. The submissions the Authority received provided useful insights and contributed to changes in the proposed service levels in the Code for market-makers. Table 3 sets out the comments from stakeholders that resulted in changes to the Code amendment.

Table 3: Submitter comments and Authority response

Submitter comment	Authority response
Bid-ask spread	
There were nine submissions providing feedback on the Authority's proposed bid-ask spread and market volume. There was general support among many stakeholders for the 3% spread: a. Non-market-making participants preferred lower spreads but supported the 3% setting as an acceptable compromise. b. Electric Kiwi, Flick, Haast Energy, Pulse Energy and Vocus, preferred the bid-ask spreads to be narrower, referencing the increase volume and open interest that	Feedback from stakeholders broadly supported maintaining the 3% spread. The single submission for a narrower spread (b) was dismissed as unreasonably tight for market-making firms and would likely lead to lower liquidity. The alternative proposals in (c) and (d) allowing for a higher spread in the opening trading session was rejected as these options significantly added to the cost of the commercial market-making proposal.

[7] Previous Commercial market-making scheme consultation proposals are available here: Consultations — Electricity Authority (ea.govt.nz)

resulted from previously lowering the spreads from 5%-3%. c. Existing market makers highlighted their need to adequately manage risk and therefore supported the ability to have higher spreads initially that would converge on the 3% level by the end of each trading period. Most market-making firms were generally supportive of the 3% level as a fallback position. d. The exception was Contact who felt the 3% bid-ask spread is too narrow for contracts at the front end of the future curve given the high volatility. Instead, they proposed a hybrid bid-ask spread with wider bid-ask spread at the front quarters and for monthly contracts, and a lower bid-ask spread in the remaining quarters. Contact believed this hybrid model spread would also achieve the intended outcome of the proposed refresh obligation.	Following consideration of the feedback from stakeholders the Authority has decided to retain the current 3% spread.
Exemption regime	
Most stakeholder submissions were supportive of the proposed changes to the exemption regime to five days in a rolling 20-day trading period. There were, however, some qualifications to this support from a small number of firms, who although supportive in principle of what the proposal was trying to achieve, suggested amendments to the design of the exemption. a. The four regulated market makers agreed with the principle and reasoning behind the proposed change but with qualification in some cases b. A common stance across the regulated market makers is that the use of exemption days is indicative of the cost of market-making (reflected in submissions from Contact, Genesis, and Meridian). c. Genesis proposed a regime of five exemption days per rolling 15 days, instead of the proposed 20 rolling days. Their rationale for the shorter rolling periods being to better reflect the cost and risks of market-making while maintaining current levels of liquidity.	Following stakeholder feedback, the Authority has decided to amend the exemption regime to five exemption days per rolling 20-day trading period. The reasons for this are as follows: Feedback by submitters showed a mixed preference, with some submissions wanting more exemption days and others wanting less. In the absence of either side presenting compelling evidence that either option would provide net positive benefits to consumers, the Authority has decided to continue with its proposed design. The number of exemption days is something that the Authority will continue to assess and seek stakeholder feedback on as the commercial market-making scheme develops further iterations of its commercial market-making arrangements. The decision to move to five exempt days in a rolling 20-day trading period removes the liquidity gaps that occur at the end of each month under the current system, while increasing market efficiency and allowing market makers

d. Most other stakeholders agreed with the proposal to reduce the period to 20 days, noting the impact that clustering of exemptions at the end of the month had on the freezing liquidity in the market. Again, there were caveats: e. Contact believes an additional permitted circumstance should be allowed where an event can be proven to have been caused by a third party and is out of the market makers control. f. Electric Kiwi, Flick, Haast Energy, Pulse Energy and Vocus felt that the exemptions should be reduced to 2 days per 20-day period rather than five days. g. Octopus Energy suggested there should be no opt outs.	flexibility to manage their risk and reduce the costs of market-making. In a market where liquidity is improved and information is more transparent, this should see the benefits of reduced costs for market participants passed on to consumers in lower prices (b) and (d).
Refresh option	
The refresh obligation caused the greatest concern for submitters, especially from regulated market makers. Most market-making firms either did not support the proposal or gave qualified support, dependent on the refresh design. In contrast, independent retailers who participated in the futures market, were broadly supportive of the proposal. a. Mercury supported the refresh obligation however, preferred the refresh obligation to be targeted, only applying to the first 12 monthly contracts. Mercury believes this would enhance the efficiency trade-off between cost of introducing the obligation, while also benefiting from improved liquidity. b. Genesis and Contact supported the proposal but wished to see a hybrid bid-ask spread if the liquidity benefits of the refresh obligation were to be realised. c. Contact felt that the refresh obligation will increase the risk of a technical failure on the part of the market maker due to the increased complexity, and it will be significantly more difficult for a market maker to assess its compliance with the market-making obligations in real-time, increasing market-making costs.	Following stakeholder consultation, the Authority has decided to make the proposed refresh option voluntary for regulated and commercial market makers. This provides flexibility for market makers who prefer to offer their full obligation volume in their first order. This decision helps improve liquidity and efficiency in the market and does not impose additional costs or complexity, addressing (a), and (c-e). The Authority rejected (b) as a hybrid spread would add costs to market participants given the estimated costs structure for the commercial market maker. With regard to the refresh being detrimental to the market, on balance the Authority feels that the collective impact of the changes that are being made to commercial market-making will enhance reliability and liquidity in the market. Following implementation, the Authority will continue to monitor performance of the market. As the Authority continues to iterate the scheme, changes can be made in the future.

d. Meridian strongly rejected the refresh proposal believing this could reduce the volume of contracts available to trade and see increased costs to market-making, instead, proposing the refresh obligation be on a voluntary basis. Alternatively, Meridian requested that if a decision was made to proceed with the proposed obligation, the Authority: allow market makers 10 minutes in the 30-minute market-making window to formulate bids and offers given the two-fold process market makers will newly be required to undertake and provide certainty of implementation timeframes far in advance. e. emhTrade did not support the obligation, expressing concern that the proposal would lead to volume reduction, increasing cost to market-making, and a reduction in the stability of the forward price curve.	
Cost-benefit analysis	
There was mixed feedback on the Authority's cost-benefit analysis: a. Electric Kiwi, Flick, Haast Energy, Pulse Energy and Vocus expressed support for the increase in the levy, only on the basis it funds a new commercial provider or if the Authority intends to increase the total volume above 12MW.[8] b. emhTrade disagreed with the Authority's stance that the refresh obligation could potentially be a significant improvement to levy payers, instead, suggesting it would result in an increase to the cost of market-making. c. Meridian disagreed with the Authority's CBA on the refresh obligation as it sees the proposal would increase financial risk for market makers, and therefore would increase costs. d. Contact disagreed with Authority's CBA for the exemption regime, suggesting that instead of seeing a lower fee for market-making of at least $500,000 per annum as proposed by the Authority, that the exemption regime would result in	The cost concerns raised by stakeholders with elements of the Authority's CBA analysis has been considered. Taking submitters' concerns into account has led to a decision to make the refresh option voluntary for regulated market makers. The 3% spread, five exemption days in a rolling 20-day trading period, and a voluntary refresh, indicate the Code amendments will result in a net positive benefit to consumers. This addresses points (a-c). Also, addressing the point raised in (d), Contact has allocated an entire additional FTE resource to address possible staff absences. This resource is unlikely to be fully allocated to this task (as it is for partial cover) and the FTE could be used for other tasks in the firm. Therefore, the full cost should not be allocated entirely to market-making.

[8] As noted earlier, the volume issue is out of scope for this consultation as it was decided previously by the Authority as part of the commercial market-making levy consultation - Long-form report (ea.govt.nz)

additional market-making and resourcing costs which will exceed $500,000 per annum.	
Code change suggestions	
a. Genesis suggested that the period of the rolling exemption provisions in the ASX market-making agreement (once settled) be mirrored in clause 13.236N(1)(b). b. Contact suggested that clause 13.236L(4) should be 13.236L(2)(b); and that on clause 13.236N9a) an additional reason (ie. 13.236N(a)(iii)) should be added to cover situations where the market maker is affected by third party issues that are out of its control. c. Mercury requested that the Authority clarify the consistency between the proposed change to a rolling twenty trading days exemption scheme and the drafting of subclauses 13.236N(1)(b) and 13.236N(2) of the proposed Code amendment. d. emhTrade said that it was not clear what 13.236L (3) means or is intended to achieve; 13.236N (1) (b) means the back-stop arrangements provide exemptions on a calendar month basis. They felt this was a drafting error.	a. Clause 13.236N(1)(b) contained a drafting error and is now corrected. b. Clause 13.236L(4contained a drafting error and is now corrected. The Authority rejected the suggestion to include an additional exemption to cover the actions of a third party in a suggested 13.236N(a)(iii). Third party issues are best managed by the market maker, and the existing exemptions should be sufficient. c. Clause 13.236N(1)(b) contained a Code drafting error and is now corrected. The subclauses are intended to reflect a reduction from five exemption days per rolling 20 trading days to two exemption days per rolling 20 trading days when the backstop in the Code is enforced. d. Clause 13.236L(3) is superfluous and has been removed. Clause 13.236N(1)(b) contained a Code drafting error and is now corrected.

5.2. Table 4 below summarises other points made in the submission that are either out of scope of the project, have been addressed previously or the Authority disagreed with the submission and why.

Table 4: Submitter comments and Authority response

Submitter comment	Authority response
<u>Electric Kiwi, Flick, Haast Energy, Pulse Energy and Vocus</u> wanted: a. the current 12MW total volume retained among the regulated market makers (at	a. The total volume of 12 MW per contract is sufficient to cover approximately 72% of average electricity demand (calendar year 2020).[9] The Authority also considered

[9] Calculation is based on total available market made capacity of 3,384 MW for hedge contracts and average electricity demand for New Zealand in 2020 of 4,699.40 MW. Market made hedge contract capacity calculation: 188 trading days x 12 MW per contract x 1.5 periods (quarterly offered all year and monthly

3MW total volume each) and use the commercial market maker as an opportunity to increase this volume by 3MW to a total of 15MW b. Contact, Genesis, Mercury, and Meridian's shares of the 12MW regulated market-making requirements to be in proportion to their generation (or generation capacity). c. Spreads to be narrower: The benefits from lowering spreads from 5% to 3% are clear. The Authority should consider the additional benefits to wholesale markets that could accrue if this is narrowed further. d. Penalties for non-compliance should be increased. The mandatory backstop should be triggered immediately when the voluntary scheme fails. Clause 13.236K should be amended by replacing "on three or more occasions in a period of 90 days" with "on any occasion" or equivalent. The threshold for "allowing market makers to return to the voluntary market after a period of good performance"11 (clause 12.236k(3)(a)) should be extended from 90 days to 365 days of compliance. e. The Authority consider the types of hedge market products/risk management tools that should be required to be available, particularly before the Authority attempts to procure incentive-based market-making services f. Exacerbator-pays is more efficient than the Authority's proposed cost socialisation. g. That generator retailers should be vertically separated. h. Octopus felt that ASX initial margins are at a prohibitively high level, and that this acts as a disincentive for smaller firms to use the ASX.	the risk of over provision of service but decided that 12 MW was appropriate because market trading volumes and open interest have continued to grow since the increased global volume of 12 MW was introduced in 2020. For reference, the average monthly contracts traded have increased from 13,221 contracts per month to 35,537 contracts per month since the global volume was increased in January 2019.[10] b. At this time the Authority does not have adequate evidence to support adopting this approach. As the market evolves, these options may be considered in future developments. c. The decision to retain the 3% spread is based on feedback the Authority received from the beneficiaries of market-making services in 2021. Evidence from commercial procurement suggested a significant cost to consumers of narrowing spreads below 3%. d. The current penalties are sufficient to create the necessary incentives on market-making firms to provide liquidity and participate in the market. e. This may be considered in future work on market-making. For now, this is out of scope. f. The Authority disagrees and considers the proposed model more efficient for reducing cost and increasing liquidity in the market in these circumstances. g. The issue of vertical integration of firms is also out of scope of this work. h. ASX margins are not in scope and are not within the Authority's control. i. The Authority agrees that this change may place downward pressure on initial margins, which is a significant cost for participants transacting on the ASX futures market. However, ASX margins are out of scope.

offered half a year) x 2 nodes (Benmore and Otahuhu) x 0.5 for the market made volume removed on opposite side of the transaction.

[10] Based on average monthly trades for 24 months prior to January 2019 versus average monthly trades for all months post January 2019 (www.emi.ea.govt.nz).

i. emhTrade expressed concerns that delays in addressing the liquidity issue (in the refresh obligation) has led to long-term higher margins from ASX.	

6. Next steps

6.1. The Code amendments will come into force 1 September 2022, following the 28-day rule Gazette period

6.2. The commercial market-making scheme will go live from 1 September 2022, with Bold Trading market-making alongside the four regulated market makers

6.3. Leading up to the implementation date, the Authority will ensuring ongoing dialogue with the five market makers (Contact, Genesis, Mercury, Meriden, and Bold Trading) to ensure the new service parameters are understood by respective parties.

7. Attachments

7.1. The following appendices are attached to this paper:

Appendix A Commercial market-making Code amendment

Appendix B Revised Cost Benefit Analysis

Appendix A Commercial market-making Code amendment

Electricity Industry Participation Code Amendment (Hedge Market Arrangements) 2022

Relevant Part 1 defined terms (and associated proposed amendments)

bid-ask spread means—

(a) if expressed as a dollar value, the dollar value that represents the difference in price between a **quote** to buy a **NZ electricity future** and a **quote** to sell a **NZ electricity future** of the same type on the same **exchange**; or

(b) if expressed as a percentage, the percentage calculated by dividing the difference between the price of a **quote** to buy a **NZ electricity future** and the price of a **quote** to sell a **NZ electricity future** of the same type on the same **exchange** by the price of the **quote** to sell a **NZ electricity future**

exchange means an exchange included in a list **published** by the **Authority** on which New Zealand electricity base load futures contracts are available for trade

NZ electricity future means a New Zealand electricity 0.1 **MW** base load equivalent futures contract in respect of the Otahuhu reference **node** or the Benmore reference **node** available for trade on an **exchange**

NZEF market-making agreement means an agreement between a **participant** and an **exchange** that imposes obligations on the **participant** in relation to the **exchange's** daily settlement market-making scheme for **NZ electricity futures**, in the form of agreement used on the **exchange** for this purpose that is satisfactory to the **Authority**, having regard to its inclusion of the requirements set out in clause 13.236L and of the permitted exemptions from the performance of market-making services

NZEF market-making period means from 1530 to 1600 New Zealand time on each **business day** on which **NZ electricity futures** are traded

quote means an offer to buy or sell a **NZ electricity future** on an **exchange**

Proposed new defined terms to be inserted in subpart 5B of Part 13, for application to subpart 5B only

order means a **quote,** or a bundle of **quotes** (at the same price) in relation to a particular month, or calendar quarter, and particular **node** simultaneously, placed on an **exchange** by a **participant** referred to in clause 13.236K(1)

total required maximum volume means 2.4 **MW** base load equivalent of **NZ electricity futures**, taking into account traded **NZ electricity futures** across both buy **quotes** and sell **quotes**

total traded NZEF means the cumulative total amount of buy **quotes** and sell **quotes** traded by that **participant** as **NZ electricity futures** up to the start of the current **volume refresh period** in that **NZEF market-making period** in relation to the applicable reference **node** (Benmore or

Otahuhu) and for the particular month or calendar quarter referred to in clause 13.236L(1) for the **participant** to which the **total traded NZEF** is being applied

volume refresh means the requirement in accordance with clause 13.236L(3) to refresh the number of **quotes** provided by that **participant**

volume refresh period means, for a particular **volume refresh**, the time period from the time the most recent buy or sell **quotes** were traded as **NZ electricity futures** until the time the **volume refresh** is completed

Substantive provisions of subpart 5B of Part 13, including proposed amendments

13.236J Contents of this subpart

This subpart provides for an active market for trading financial hedge contracts for **electricity** by specifying requirements for certain **participants**.

13.236K Application of subpart

(1) Subject to subclause (2), this subpart applies to the following **participants**:
- (a) Contact Energy Limited;
- (b) Genesis Energy Limited;
- (c) Mercury NZ Limited;
- (d) Meridian Energy Limited.

(2) This subpart applies to a **participant** specified in subclause (1) if that **participant**—
- (a) is not a party to a **NZEF market-making agreement** that includes the requirements set out in clause 13.236L; or
- (b) does not perform market-making services in accordance with the **NZEF market-making agreement** on three or more separate occasions in a period of 90 days, and that non-performance is not permitted by an exemption or otherwise under the **NZEF market-making agreement**.

(3) A **participant** to whom subclause (2) applies is relieved of its obligations under this subpart when the **Authority**—
- (a) is satisfied that the **participant** has complied with its obligations under this subpart for a period of 90 days; and
- (b) has given written notice to that effect to the **participant**, which the **Authority** must do within 5 **business days** of being satisfied as to compliance.

13.236L Requirement to quote

(1) Subject to subclauses (2) to (5), the **participant** must, for a minimum of 25 minutes in every **NZEF market-making period**, provide **quotes** for a minimum of
- (a) 24 monthly **NZ electricity futures** for each of the Otahuhu reference **node** and the Benmore reference **node** (being 24 buy **quotes** and 24 sell **quotes** for each reference **node**) for the current month and each of the five months following the current month; and
- (b) 24 quarterly **NZ electricity futures** for each of the Otahuhu reference **node** and the Benmore reference **node** (being 24 buy **quotes** and 24 sell **quotes** for each reference **node**) for each quarter that is available for trade on an **exchange**.

(2) The **participant** must not provide a **quote** under subclause (1) with a **bid-ask spread** that exceeds the greater of 3% or NZ$2. For the avoidance of doubt, where there are multiple buy **quotes** and sell **quotes** for a particular reference **node** for a particular month or calendar quarter in a **NZEF market-making period**, the requirement in this subclause

means the **bid-ask spread** between the lowest priced buy **quote** and the highest priced sell **quote** (across those multiple **quotes**) must not exceed the greater of 3% or NZ$2.

(3) Under subclause (1) for each **NZEF market-making period**, the **participant** must provide a quantity of initial **quotes** and (as applicable) **volume refresh** its **quotes** until it has traded the **total required maximum volume** for each of the Otahuhu reference **node** and the Benmore reference **node** in relation to each particular month and calendar quarter as follows:

(a) when first placing **orders** at or after the start of the **NZEF market-making period**, the **participant** is required to place a buy **order** of at least 12 **quotes** in total and a sell **order** of at least 12 **quotes** in total;

(b) if either initial buy **order** or sell **order** is fully traded then that **participant** must (as applicable) **volume refresh** its **order(s)** such that where the amount of the **total traded NZEF** up to that point in time in the **NZEF market-making period** is— -+

(i) 12, then at the end of the **volume refresh period** the buy **order** must comprise at least 12 **quotes** and the sell **order** must comprise at least 12 **quotes**;

(ii) greater than 12, then at the end of the **volume refresh period** that **participant** must ensure that the number of **quotes** comprising each of the buy **order** and sell **order** respectively are a minimum of *X*, where—

$$X = 24 \textbf{\textit{ quotes}} - \textbf{\textit{total traded NZEF}}$$

(c) once the **participant** has traded the **total required maximum volume** it may withdraw any remaining **quotes**.

(4) A participant required to **volume refresh** in accordance with clause 13.236L(3)(b) may also carry out any other changes not inconsistent with their obligations under this subpart 5B that the **participant** chooses to make to any other **order(s)** for the particular month or calendar quarter and particular reference **node** that is the subject of the **volume refresh**.

(5) For the purpose of determining whether a **participant** has met the minimum time requirement of 25 minutes under clause 13.236L(1), a **quote** will not be treated as being provided during a **volume refresh period**.

13.236M *[Revoked*]

13.236N Exemptions from requirement to quote

(1) The **participant** is exempt from the requirements in clause 13.236L in the following circumstances:

(a) for a **NZEF market-making period** if—

(i) the **participant** cannot comply with a requirement in clause 13.236L in that **NZEF market-making period** because an **exchange** trading platform is disrupted or unavailable; or

(ii) in the reasonable opinion of the **participant**, entering into a contract for a **NZ electricity future** in that **NZEF market-making period** may cause the **participant** to breach an applicable law;

(b) in addition to the exemptions in paragraph (a), for up to two **NZEF market-making periods** within any 20 consecutive **NZEF market-making periods** at the **participant's** discretion.

(2) To avoid doubt, if the **participant** meets the criteria for exemption in subclause (1)(a)(i) or (1)(a)(ii) in relation to a **NZEF market-making period**, that **NZEF market-making period** will not count towards the **participant's** two exemptions in subclause (1)(b).

(3) If the **participant** relies on an exemption under this clause 13.236N from the requirement to **quote**, the **participant** must notify the **Authority** of the exemption it has relied on and the basis for the exemption as soon as practicable but in any case no later than 1700 New Zealand time on the same **business day** that an exemption is relied on.

Appendix B Revised Cost Benefit Analysis

Update of the mandatory backstop for final scheme design

Cost benefit analysis

01 July 2022

Market Design

1 Executive summary

1.1 In August 2020 the Electricity Authority (Authority) decided to pursue an enduring market-making approach that enhances the existing market-making arrangements while improving efficiency, increasing trust and confidence in the market, and facilitating a service-oriented approach.

1.2 A commercial market-making scheme will build on the current arrangements, where market-making is provided by Contact Energy Limited, Genesis Energy Limited, Mercury NZ Limited and Meridian Energy Limited (the four regulated market makers).

1.3 In March 2022, the Authority published a consultation paper[1] with a cost-benefit analysis assessing the proposed changes to the Electricity Industry Participation Code 2010 (Code). This assessment revises the March 2022 cost-benefit analysis with new information from the final stage of procurement and additional analysis of trading data.

1.4 The current arrangement with the four regulated market makers is used as the counterfactual or status quo and will be assessed alongside the proposed commercial market-making scheme.

1.5 There are two parts to the assessment; the introduction of commercial market-making and the changes to the scheme design. The scope of this assessment is to determine if the final design scheme following the Code amendment consultation, results in a long-term net benefit for New Zealand consumers.

1.6 The assessment has determined a commercial market-making scheme is expected to be a long-term net benefit for consumers because it will enhance the performance of the New Zealand electricity futures market, which:

(a) allows New Zealand electricity market participants to benefit from a robust and liquid forward price curve;

(b) allows those that trade in the ASX[2] futures market to benefit from liquidity and price efficiency supported by market-making; and

(c) allows for greater competition in the retail and generation markets.

1.7 Along with the net benefits provided by the introduction of a commercial market-making scheme the proposed changes to the market-making scheme design are expected to provide additional net benefits.

1.8 The two key changes from the existing market-making service levels are the proposal for a modified exemption regime and the addition of a voluntary refresh obligation.

1.9 Reduction in service fees for commercial market-making from introducing these two key changes are expected to exceed any costs to market makers, and with the addition of the qualitative benefits, it is expected to be net beneficial. A few of the qualitative benefits discussed in this cost-benefit analysis are the reduction in financial risk for market makers, reduction in market volatility, and improvement in market liquidity.

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1 Reference: https://www.ea.govt.nz/assets/dms-assets/29/Hedge-Market-Enhancements-Commercial-market-making-scheme-Code-Amendment-Consultation-paper.pdf

2 Australian Securities Exchange Limited

1.10 Due to the commercial sensitivity of certain information not all costs and benefits can be fully quantified, however the qualitative costs and benefits discussed in this cost-benefit analysis provides a detailed record of expectations.

1.11 It is the Authority's view that the proposed introduction of a commercial market-making scheme and changes to the market-making scheme design will overall result in long-term net benefits for consumers.

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2 Introduction

2.1 The Authority's *Hedge Market Enhancements: Market-Making project* [3] *(HME)* purpose is ensuring market-making services support a robust forward price curve and enable efficient risk management for the long-term benefit of consumers.

2.2 In August 2020 the Authority decided to pursue an enduring market-making approach that secured the benefits of the (then) current arrangements while enhancing efficiency, improving trust and confidence in the market, and facilitating a service-oriented approach. [4] The enduring market-making approach:

(a) transitions, over a period of years, to an incentivised market-making arrangement where market-making services are performed by providers compensated on commercial terms by all generators and purchasers (including the existing market makers); and

(b) ensures the integrity of market-making services is maintained in the transition period through a combination of regulated market makers and commercial market makers.

2.3 The current regulated market-making service level and associated parameters are in Part 13 of the Electricity Industry Participation Code (2010) (Code), and act as a mandatory backstop for market makers.

2.4 The current arrangement was derived from an urgent Code amendment to insert a dormant mandatory market-making scheme into the Code temporarily in January 2020, to address the reduction in market-making performance in the New Zealand electricity futures market during (and after) gas outages in 2018 and 2019, and in preparation for a anticipated supply pressures in 2020.

2.5 This temporary measure was implemented in accordance with section 40 of the Code and existed from February 2020 to November 2020. As part of the Authority's enduring approach to market-making the Code was amended to address the backstop's expiry, by making the mandatory backstop permanent in April 2021.[5]

2.6 This cost-benefit analysis informs the proposed change to the mandatory market-making backstop Code, to introduce a commercial market maker and to ensure alignment between the service levels for commercial and regulated market makers.

3 Scope of work

3.1 This cost-benefit analysis focuses on assessing the proposed changes to the Code. There are two parts to the assessment; the introduction of commercial market-making and the changes to the scheme design. The scope of this assessment is to determine if the proposed Code amendment consultation results in a net benefit for New Zealand consumers.

3.2 As noted by the cost-benefit analysis conducted for the introduction of a permanent mandatory backstop, data limitations continue, particularly around the details of benefits

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3 Information on this project is available at: https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development.

4 Information on this project is available at: https://www.ea.govt.nz/assets/dms-assets/27/27289Market-making-decision-summary.pdf.

5 Information on this project is available at: https://www.ea.govt.nz/assets/dms-assets/28/Decision-paper-on-permanent-mandatory-market-making-backstop.pdf.

to participants. The Authority has relied on information gathered from prospective market makers during the still active procurement process to inform the policy development. As a result of the procurement process still being active, the Authority considers the detailed information gathered is still commercially confidential. Therefore any information presented is a summarised version.

Problem and opportunity definition

3.3 New Zealand consumers indirectly benefit from market-making as these services allow retailers to manage future price risk through hedging. Without these services, electricity consumers would likely face higher prices as retailers would face less efficient methods of managing the price risk.

3.4 In October 2018 there was an unscheduled outage at Pohokura gas field, which caused price volatility and large increases in near-term electricity futures contract prices. Spreads in the New Zealand electricity futures market widened significantly, and trading volumes reduced. Following the events of October 2018, market-making activities took significant time to restart following the period of high volatility.

3.5 Although the Authority amended the Code to include temporary, and subsequently permanent provisions for a mandatory market-making backstop to address previous and to deter future instances of poor performance, the Authority determined future changes were required to address two key issues:

(a) *a lack of confidence by some stakeholders in market-making and the market for exchange traded contracts. Confidence can be addressed under an approach if it allows for increasing the number and diversity of market makers and has strong incentives for services to be provided*.

(b) the current arrangements are not 'service-oriented' and so consumers and beneficiaries of market-making services cannot signal a desire for service level change (including improved reliability) and their willingness to make the necessary trade-offs (such as meeting the costs of improved reliability).

3.6 The Authority intends to introduce commercial market makers to market make alongside the existing regulated market makers. For market-making to succeed the regulated market makers and commercial market makers, must both operate under the same service levels in the Code.

4 Introduction of commercial market-making

4.1 The Authority will replace 20% of the mandatory market-making obligation with commercial market maker(s). The costs of introducing a commercial market maker will be an increase in the Electricity Authority levy. However, the Authority views the change in the levy as a wealth transfer. The Authority's treatment of a wealth transfer is set out in the Authority's interpretation of the Statutory objective:

> *Competition limb*
>
> *2.2.1 In regard to competition the Authority notes that:*
>
> *(c) the benefits of competition refer to efficiency benefits, not wealth transfers, arising from price movements, but it includes any efficiency effects that may arise from wealth transfers*

4.2 Under a full mandatory scheme the costs of market-making are incurred by the mandated market makers, and are ultimately borne by the generation and purchaser arms of the market maker. The costs of the commercial scheme will be borne by all generators and purchasers. This transfer of costs is a wealth transfer and is not a cost. However, there are efficiency gains from a situation where market-making is mandatory to one where it is commercially determined.

4.3 Currently, only some participants bear the cost of market-making, however a majority of participants benefit from it either directly, or indirectly. Allocating the cost of market-making to all generators and all purchasers will better align the cost and the benefit of market making.[6]

4.4 A commercial process to determine a market maker allows for more efficient (lower-cost) suppliers to be introduced to provide market-making services. The existing market makers may be the most efficient at providing services, however without a market-based assessment, this is uncertain.

4.5 A further advantage of the introduction of the commercial scheme is the ability for levy payers to influence the level of service provided. In 2021, the Authority conducted a levy consultation.[7] This allowed levy payers the opportunity to note their preferences for the level of service provided. Under a mandatory scheme, this formal feedback is not available, and the most optimal level of service may not be known.

4.6 The introduction of commercial market-making may have a new market maker provide services. This will increase the diversity of market makers. A greater diversity in market makers would see new entities providing market-making services. This would mean firms who are not currently physical market participants (as defined in the Code), such as banks, trading houses or other financial service providers may enter.

4.7 Accessing a wider pool of market makers will introduce more information to the forward price curve, contributing to greater reliability and greater market participant confidence in the forward price curve. The Authority notes that discussions with stakeholders saw widespread support for the proposition that introducing a more diverse set of market makers would increase confidence in futures prices.

4.8 The Authority notes the option value of the decision to initially create 20% of the market-making obligation for a commercial scheme. With all choices to change the market design, there is implementation risk. The Authority has chosen a deliberate step towards a full commercial scheme, with specific and deliberate decisions to change the mix between mandated and commercial. Should the introduction of a commercial scheme not prove in the long-term benefit of consumers, the Authority notes the implementation of fully mandated market-making would be less risky under the proposed stepped change.

5 Market-making scheme design changes

5.1 Regulated market-making is currently provided entirely by four integrated generator/retailers, Contact Energy Limited, Genesis Energy Limited, Meridian Energy Limited and Mercury NZ Limited.

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6 Reference: https://www.ea.govt.nz/assets/dms-assets/28/Levy-consultation-Commercial-Market-Making-Scheme-Consultation-paper.pdf

7 Available at https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/consultations/#c18887

5.2 The current regulated market-making key service levels will be used as the counterfactual or status quo and are as follows:

(a) total volume of 12MW per contract with each regulated market maker providing 3MW per contract each;

(i) 30 lots (3MW baseload equivalent) per side.

(b) spreads no more than the greater of 3% or $2;

(c) covering the front 6 months of monthly contracts, and all available quarterly baseload contracts;

(d) each market maker has five discretionary exemptions from providing services each calendar month;

(e) no refresh obligation for contracts offered.

5.3 The future market-making key service levels are as follows:

(a) total volume of 12MW per contract with each regulated and commercial market maker providing 2.4MW per contract each;

(i) 24 lots (2.4MW baseload equivalent) per side.

(b) spreads no more than the greater of 3% or $2/MWh[8];

(c) covering the front 6 months of monthly contracts, and all available quarterly baseload contracts;

(d) each market maker has five discretionary exemptions from providing services each rolling 20 trading days;

(e) inclusion of a voluntary refresh obligation (with at least half of total volume posted upfront with an option for a top up to meet the volume obligation if required).[9]

5.4 The key change in service levels are the change in exemption regime and the change in the refresh obligation.

Impacts of proposed commercial service levels

5.5 The Authority's cost-benefit analysis[10] in 2011 for introducing market-making obligations, provided a high-level summary of the benefits from improved market-making arrangements. The diagram in Figure 1 provides the linkage between market-making and economic benefits.

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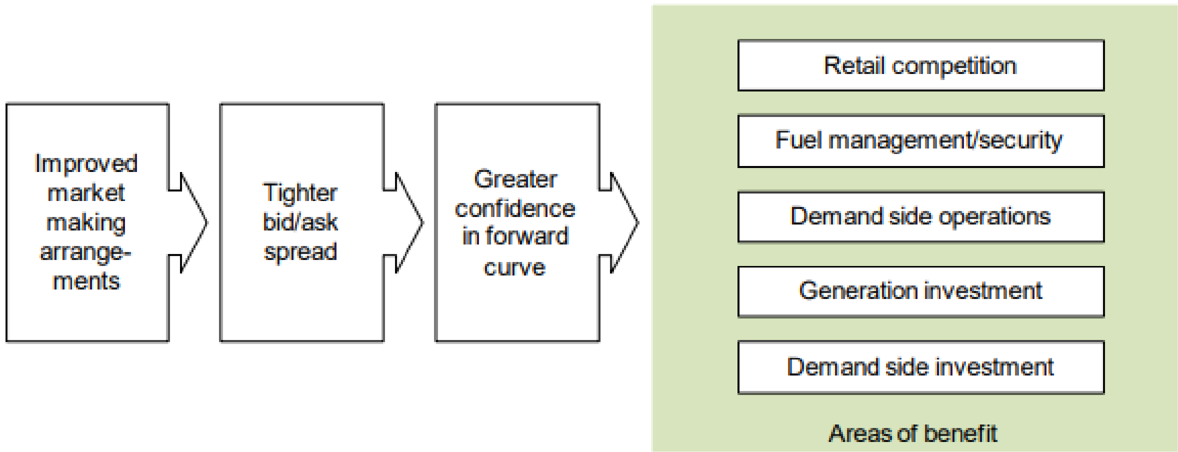
8 The financial cost-benefit trade-off for spread cannot be determined until price schedules are provided in the next stage of procurement (Request for Proposal - RFP

9 The previous version of this cost benefit analysis discussed a mandatory refresh obligations scheme.

10 Information on this project is available at: https://www.ea.govt.nz/assets/dms-assets/12/12085CBA-Paper-Market-Making-Obligations.pdf.

Figure 1 Linkage between market-making and economic benefits



5.6 The 2011 cost-benefit analysis also provided the following explanation for each of areas of benefits:

(a) *stronger retail competition, because parties entering or expanding their presence in the retail market are able to better manage their exposure to price risk;*

(b) *improved fuel management (hydro and thermal fuels) decisions because parties have a more robust indicator of expected future conditions;*

(c) *improved demand-side operating decisions, such as whether to commit to a production order or buyback contract, because they have a more robust indicator of expected conditions and greater confidence to enter into contracts;*

(d) *improved generation investment decisions leading to stronger generation competition, because parties have a more robust indicator of expected future conditions; and*

(e) *improved demand-side investment decisions, such as whether to expand production facilities or develop demand response capacity, because they have a more robust pricing benchmark for the future.*

5.7 The following are the identified costs and benefits to industry stakeholders from implementing the proposed service levels in the Code for commercial and regulated market-making, when assessed against the counterfactual or status quo.

5.8 The assessment intentionally includes all industry stakeholders and not only hedge market participants because all industry stakeholders are indirectly impacted by the proposed changes.

Table 1 Cost-benefit impacts for each market-making service provision

Exemptions: Each market maker has five discretionary exemptions from providing services each rolling 20 trading days.	
Benefits	Costs
• Reduces volatility due to concentration of exemptions taken by market makers at the end of calendar month. This will be especially pronounced around the December/January holiday period where market-making would not currently occur for over three weeks. • Reduces financial risk for market makers because the probability of being a sole market maker on a given trading day is less likely. • Reduces the financial risk for market participants in increasing the likelihood of being able to transact at the end of the month. • Participants will benefit from a more accurate forward price curve at the end of each month, reducing volatility in settlement prices at month end.	• There will be some costs to monitoring of the exemption regime, however these costs in relative terms are negligible. • Market makers may face increased costs from market-making on days at the end of the month. However, these costs are expected to be minimal as days with high cost would see an exemption day taken anyway.

The procurement process[11] suggested the majority of existing regulated and potential commercial market makers saw the change to a rolling exemption regime would result in a reduced cost of service provision (at least 5%).

The trade-off between the number of exemption days permitted in a rolling period and the impact on market availability and the cost of commercial market making was considered.

Additional exemption days reduce the volume of futures contracts available for market participants. The Authority would expect regulated market makers to provide services for fewer days on average. The reduction in service may reduce trade volume and lower price discovery, resulting in a less robust forward curve. This will increase costs for market makers who choose to remain in the market, and eventually leading to greater costs for consumers in the long-run.

Market makers providing services on fewer days impacts the cost of remaining market makers in two ways:

(a) on average there will likely be fewer market makers during some trading days. This reduced presence of market makers reduces contracts for market makers to trade against; and

(b) the probability of all market makers not participating on a given day increases, resulting in more risk for a given market maker being the sole market maker on any given day, increasing the risk of adverse trading outcomes.

Five exemption days per rolling 20-day trading period is expected to provide a balance between providing market makers with appropriate opportunities to manage risks and improving the robustness of the forward curve.

11 Request for Information (ROI)

<table>
<tr><td colspan="2">Voluntary Refresh obligation: Inclusion of a voluntary refresh obligation (with at least half of total volume posted upfront with an option for a top up to meet the volume obligation if required).</td></tr>
<tr><td><u>Benefits</u></td><td><u>Costs</u></td></tr>
<tr><td>• Potentially reduces instantaneous trading at market opening between market makers i.e. improving market volume depth for participants[12]
• It is expected that reducing these instantaneous trades will increase the likelihood of buy and sell prices remaining at the conclusion of the market-making window
• A voluntary approach instead of a mandatory approach enables market makers to determine the best strategy specific to their market-making operations
• The imposition of a voluntary refresh reduces the cost of market making provision by a commercial party</td><td>• The Authority will require one-off alterations to existing exemption monitoring and compliance</td></tr>
<tr><td colspan="2">The benefits of introducing a voluntary refresh obligation have the potential to be significant to levy payers.

Procuring a scheme without a refresh obligation at a higher fee and the impact of reduced volume available on the market, and the potential for increased trading aggression at market opening was considered.

The reduced volume available at a given point in time, potentially results in market participants having to fill their orders in two separate transactions with the second transaction occurring at a different price relative to the first transaction. This is because under a refresh obligation, market makers can adjust prices for refreshed volume to take advantage of demand from market participants. The Authority considers the improved granularity in trading will assist in price discovery and more efficient prices for market participants.

The reduction in service fee is considered to exceed any costs to market makers and market participants, and with the addition of the qualitative benefits noted, it is expected to be for the long-term benefit for consumers.</td></tr>
</table>

12 In the March 2022 consultation paper, the cost-benefit analysis provided, referred to the opening trading as inadvertent. Further analysis by the Authority observing the ratio of net position over volume churn for each market maker individually over a period of 6 months, appeared to suggest the volume churn was used to obtain a position in the market. It is inconclusive if the previous referred to ‘inadvertent’ trades are indeed inadvertent, hence the terminology, ‘instantaneous’ trades is preferred.

6 Conclusion

6.1 The introduction of a commercial market-making scheme is expected to be a net-benefit to consumers as it will enhance the performance of the New Zealand electricity futures market by:

(a) allowing New Zealand electricity market participants to benefit from a robust and liquid forward price curve;

(b) allowing those that trade in the ASX[13] futures market to benefit from liquidity and price efficiency supported by market-making; and

(c) allowing for greater competition in the retail and generation markets.

6.2 Along with the net benefits provided by the introduction of a commercial market-making scheme the proposed changes to the market-making scheme design are expected to provide additional net benefits, such as reducing financial risk for market makers, reducing market volatility, and improving market liquidity.

6.3 It is the Authority's view that the proposed introduction of a commercial market-making scheme and changes to the market-making scheme design will overall result in net long-term benefits for consumers.

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[13] Australian Securities Exchange Limited