Dispatchable demand during tight market conditions

Consultation Paper

Submissions close: 5.00pm 1 March 2016

15 January 2016

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Executive summary

The dispatchable demand regime (DD regime) allows a dispatch-capable load station (DCLS) to submit dispatch bids that the system operator can control by issuing dispatch instructions.

Currently there is only one party that actively submits dispatch bids for a DCLS. Norske Skog submits these bids for its load at the KAW0113 node (located at Kawerau in the Bay of Plenty region).

When the DD regime was developed, the Authority's original design would have allowed the system operator to dispatch participating load in real time, using the same real time dispatch schedule (RTD) as for generators and the same dispatch process. However, this would have required expensive changes to the system operator's systems. Consequently, a modified design was introduced under which participating loads are dispatched from the non-response schedule (NRS) produced during the 30 minutes before the start of the trading period. The Code does not specify exactly when during that 30 minutes the NRS is to be produced. The system operator produces the NRS approximately 25 minutes before the start of the trading period, to allow adequate time to carry out its security assessment.

When the DD regime was being designed, it was envisaged that a DCLS would not have "must run" load (like factory lighting, control systems, etc.) participating in the DD regime. If a participant had must run load, the DCLS could be defined in such a way as to exclude that load.

The problems discussed in this paper arise from a combination of:

(1) the move from the original design to the modified design

(2) the system operator's decision to dispatch participating loads 25 minutes before the start of the trading period rather than much closer to the start of the trading period

(3) Norske Skog's decision to define its DCLS in such a way that it includes must run load

(4) a lack of clarity for DCLSs as to how market systems and processes would perform if a DCLS bid its must run load above $100,000/MWh to ensure its dispatch.

Together these factors mean that a DCLS's must run load can be dispatched off when supply conditions become tight, which can lead to clearly inefficient outcomes.

The Authority has identified three related problems of the DD regime that could potentially occur when supply conditions are very "tight" – that is, when there is insufficient, or close to insufficient, generation and reserves to meet load and reserve requirements:

(a) ***Inefficient dispatch***: Inefficient dispatch can occur for high value dispatch bid bands (that is, bid bands with a value above around $15,000/MWh). In particular, that high value load can be dispatched off when it would have been possible to achieve greater overall sector benefits by: dispatching the load on, waiting to see if there is any late voluntary response and, if there is no such response, directing mandatory load curtailment or operating on reduced reserves.

(b) ***Market prices above genuine scarcity levels***: It is possible for very high market prices (eg, $50,000/MWh) to occur which are substantially above levels reflecting marginal system costs during scarcity conditions. Such prices could cause large wealth transfers, which in turn create costs for participants trying to manage these risks, and undermine participants' confidence in the wholesale market.

(c) ***Constrained off payments***: (This can be viewed as a symptom of the first problem.) Large constrained off payments can occur in relation to high value dispatch bid bands due to the inefficient dispatch of those bid bands. This creates incentives for inefficient behaviour by dispatchable demand participants that are directed towards capturing those constrained off payments.

The Authority is proposing to amend Part 13 of the Code to provide that a dispatchable demand participant must price dispatch bid bands for its DCLS at or below $15,000/MWh or at $600,000/MWh (that is, above the level of the constraint violation penalties (CVPs)).

If the DCLS has must run load, it can be bid at $600,000/MWh and will always be dispatched on. Any DCLS load that is not must run can be bid at or below $15,000/MWh and will be dispatched on or off based on market conditions.

This is expected to promote efficient dispatch of DCLSs, reduce the likelihood of market prices rising above the cost of available alternatives such as mandatory load curtailment, and eliminate constrained off payments arising from the inefficient dispatch of DCLSs.

The net present value of the proposal is expected to be $1.48 million, excluding any dynamic efficiency benefits. This consists of benefits with a present value of $1.51 million and costs with a present value of $30,000. Dynamic efficiency benefits could emerge from increasing participant and public confidence in the wholesale electricity market, but the Authority has not quantified this benefit. The Authority believes the benefits of the proposal (compared with the status quo) are likely to exceed the costs, even with no dynamic efficiency benefits.

The Authority has considered and evaluated five alternative options. These are considered less favourable than the preferred proposal.

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1. Your feedback is welcome

1.1 What this paper is about

1.1.1 The Authority is proposing to amend Part 13 of the Electricity Industry Participation Code 2010 (Code) so that a dispatchable demand participant must price dispatch bid bands for its DCLS at or below $15,000/MWh or at $600,000/MWh

1.1.2 This is expected to achieve a more efficient dispatch of must run DCLS dispatch bid bands.

1.1.3 The proposed changes to the Code are set out in Appendix A.

1.1.4 The purpose of this consultation paper is to inform participants and persons likely to be affected by the proposal, and to invite feedback on this proposal.

1.2 How to make a submission

1.2.1 Your submission is likely to be made available to the general public on the Authority's website. If necessary, please indicate any information that is provided to the Authority on a confidential basis. However, you should be aware that all information provided to the Authority is subject to the Official Information Act 1982.

1.2.2 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "Consultation Paper—Dispatchable demand during tight market conditions" in the subject line.

1.2.3 Do not send hard copies of submissions to the Authority unless it is not possible to do so electronically. If you cannot or do not wish to send your submission electronically, you should post one hard copy of the submission to either of the addresses provided below or you can fax it to 04 460 8879. You can call 04 460 8860 if you have any questions.

Postal address

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Physical address

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

1.3 Deadline for receiving a submission

1.3.1 Submissions should be received by **5pm** on **1 March 2016**. Please note that late submissions are unlikely to be considered. The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

2. Issue the Authority would like to address

2.1 The existing arrangements

Dispatchable demand and the non-response schedule

2.1.1 The Code was amended in mid-2014 to include dispatchable demand provisions. The provisions provide an opportunity for electricity users to elect to be dispatched based on their bid into the market (in a broadly similar way to generators). A participant can apply to have its load recognised as a "dispatch-capable load station" (DCLS). Once approved, the participant can then submit "dispatch bids"[1] for that load. The system operator dispatches those loads. The participant is then known as a "dispatchable demand participant". It remains optional for an approved DCLS to be subject to dispatch in any particular trading period. Dispatch bids for a DCLS are used in the final pricing schedule and may set the final price.

2.1.2 Two DCLSs have participated in the regime since November 2014. Norske Skog operates them both:

(a) the first DCLS is located at the KAW0113 node (in Kawerau in the Bay of Plenty region) and Norske Skog has routinely submitted dispatch bids for it since 20 November 2014

(b) the second DCLS is located at the KAW0112 node (also in Kawerau), but Norske Skog has only submitted dispatch bids for it for four days (20 to 23 November 2014, inclusive).

2.1.3 Dispatch instructions for DCLSs are created from the NRS.[2] The system operator normally runs the NRS once each trading period to cover the current trading period plus the following seven trading periods. The NRS commences solving about three minutes after the start of each trading period, and the results are normally available within a further two minutes. The dispatch instructions are for the next trading period (not the current trading period) and are issued automatically through the Wholesale Information and Trading System (WITS).[3] Consequently, dispatch instructions applying to a trading period are normally issued to the DCLSs around 25 minutes before the start of that trading period.

2.1.4 In this paper, the term "dispatch-NRS" (with reference to a trading period) refers to the NRS for that trading period that was run during the previous

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1 In Part 1 of the Code these are called "nominated dispatch bids".

2 The actual NRS used is the "short" version as defined in clause 13.62(1)(b) of the Code. This is commonly called the NRSS, the non-response schedule (short).

3 The NRS covers eight trading periods, but it is only the scheduled quantities from the second of those eight trading period that become dispatch instructions to DCLSs.

trading period and produced dispatch instructions to DCLSs for that trading period. While an NRS covers eight trading periods, the term “dispatch-NRS” refers to the second of those eight trading periods within the NRS.

Dispatch bids

2.1.5 Dispatch bids can have up to ten bands. Each band includes a quantity of electricity in MW and a price (in $/MWh) below which the DCLS wishes to use/purchase the stated quantity of electricity.

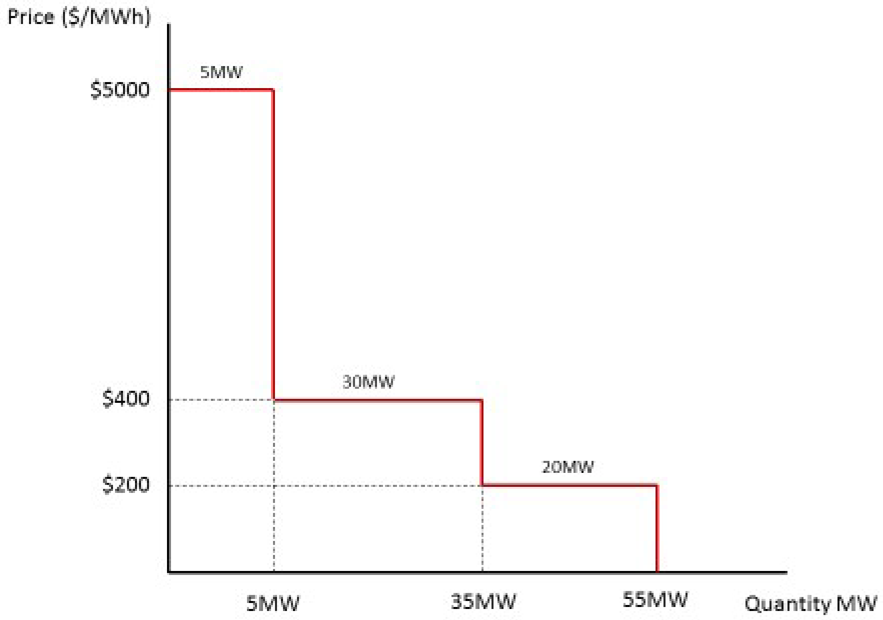
2.1.6 Figure 1 illustrates a dispatch bid with three bands:

(a) the first band is for 5 MW at any price below $5000/MWh

(b) the second band is for an additional 30 MW at any price below $400/MWh

(c) the third band is for an additional 20 MW at any price below $200/MWh.

Figure 1: Example of a dispatch bid



2.1.7 In principle, a DCLS’s bid band price represents the value of that additional electricity usage to the DCLS. This market design creates some pressure for a DCLS to reveal through its bid its genuine assessment of the value it obtains from electricity usage.[4]

[4] If it does not reveal its genuine assessment of that value, the DCLS may be scheduled and dispatched either (a) to use electricity at a price higher than the actual benefit the DCLS gets from using the load, or (b) to not use electricity at a price lower than that actual benefit.

The optimisation engine and infeasibilities

2.1.8 All schedules use the same optimisation engine known as "SPD" (Scheduling, Pricing, and Dispatch). The optimisation aims to maximise the net benefits from trading electricity subject to certain constraints.

2.1.9 The net benefits from trading electricity that are optimised by SPD are:

(a) ***The value to electricity users of using electricity***, as revealed by bids. This is essentially the "area below the demand curve". If some load has not submitted bids (eg, where the load is centrally forecast), there is no bid information available for that load, but it can be assigned an arbitrary fixed value because it does not affect the solution to the optimisation problem.

Minus

(b) ***The cost of generation***, as revealed by offers.

Minus

(c) ***The cost of reserves***, as revealed by reserve offers.

2.1.10 The constraints include the following requirements (among many others):

(a) supply (less transmission losses) must equal demand

(b) electrical flows through transmission assets must be less than the assigned capacity of the transmission asset

(c) sufficient instantaneous reserves must be scheduled.

2.1.11 When the system operator "runs" a schedule, the schedule will produce a solution that includes a set of scheduled quantities for all offered generation, offered reserves, and bid load.[5] The solution can also include a set of energy and reserve prices. The energy price at a node indicates the modelled additional cost to the system as a whole of meeting a marginal increase in load at that node.

2.1.12 If there are insufficient generation and reserve offers to meet load, there will be no physical solution to the optimisation for that schedule. This is known as an "infeasibility". Although there is no physical solution, the optimisation engine does in fact reach a solution by scheduling virtual (non-physical) resources.

2.1.13 The virtual resources have very high costs assigned to them known as "constraint violation penalties" (CVPs). Two of the most common virtual resources are virtual generation and virtual reserves (both fast and sustained instantaneous reserve: FIR and SIR) for meeting a contingent event.

[5] "Bid load" is any load for which bids are submitted and used as an input into the schedule.

2.1.14 The CVP for reserves is $100,000/MWh and the CVP for generation is $500,000/MWh.

2.1.15 If tight market conditions consist of a shortage of both energy and reserves (as is often the case in a shortage), the optimisation will tend to resolve the physical infeasibility by scheduling virtual reserve in preference to virtual energy since the reserve CVP is lower than the generation CVP. This means a schedule will produce a solution with less physical FIR and/or SIR than is normally required, but will continue to schedule enough generation to match scheduled electricity usage.

Management of tight market conditions after DCLSs are dispatched

2.1.16 As noted above, DCLSs normally receive their dispatch instructions around 25 minutes before the start of the trading period to which the dispatch instruction applies. At this time, the prices from the dispatch-NRS are published for all participants to see. If the system operator decides to re-run the dispatch-NRS, the dispatch instructions to DCLSs will be re-issued closer to the beginning of the trading period (and the dispatch-NRS prices will be republished); but this is not a common occurrence.

2.1.17 Some non-dispatchable electricity users and unoffered generators may monitor the forecast prices from the dispatch-NRS and consider responding. An electricity user that pays spot prices (at least "at the margin") might decide on the basis of forecast prices or other price indications that final prices are likely to be higher than they are willing to pay. That electricity user may reduce its electricity usage either prior to or during the relevant trading period. Similarly, an unoffered generator that has some control over its generation quantity may decide that final prices are likely to be sufficiently high to justify starting up or increasing its generation. In this paper we refer to these load and generation actions as "late voluntary response". It is "late" because it occurs after DCLSs receive their dispatch instructions.

2.1.18 If the system operator dispatches off high value DCLS load and late voluntary response subsequently occurs, then with hindsight it may have been more efficient to have dispatched-on the high value DCLS load. However, it would be difficult to dispatch-on high value DCLS load based on the hope that voluntary response occurs. It may not occur, in which case other more expensive measures may be required.

2.1.19 The system operator runs RTD approximately every five minutes. The solution to RTD is used to create dispatch instructions for offered generation and reserves to meet system needs.[6] The dispatch instructions are issued immediately and must be responded to promptly (so the

[6] When calculating the value to electricity users of using energy (in paragraph 2.1.9(a) above), RTD does not use any bids at all, even for load that has submitted a dispatch bid. Essentially RTD treats load as "given" (determined exogenously) and schedules generation and reserves to meet that load.

instructions are "real time" dispatch). As market conditions get tighter, RTD will begin to schedule the most expensive offered generation and offered reserve bands.

2.1.20 If the system operator expects there will be insufficient dispatchable resources to meet system requirements, it can:

(a) ***Reduce reserves***: If there are insufficient generation and reserve offers to meet load, RTD will reduce its dispatch of physical FIR and/or SIR to below the level normally required, but will continue to dispatch generation to meet demand. This means the system will be taking some additional risk. If a large generator or transmission asset was to trip off, there may not be sufficient physical reserves available to manage the resulting fall in system frequency. If system frequency cannot be arrested by instantaneous reserves, automatic under-frequency load shedding (AUFLS) could be triggered which could result in more widespread and sustained loss of load. In other words, operating with reduced reserves creates a risk of large economic costs (AUFLS trip) being incurred.

(b) ***Curtail load***: The system operator can also request that a purchaser or a distributor reduces its demand.[7] This instruction may achieve load reductions for a single trading period or over a longer period of time.[8] The instruction may refer to a specific region within an island or to a whole island (or both islands). If it refers to an island (or both islands), the system operator will declare an island-wide (or national) shortage situation which has implications for final pricing (see below).

2.1.21 From an overall efficiency perspective, the decision whether to "dispatch off" high value DCLS load in the dispatch-NRS should be weighed against the subsequent "near real time alternatives". The near real time alternatives are to wait for late voluntary response, reduce reserves and/or to direct mandatory load curtailment.

Settlement pricing in tight market conditions

2.1.22 Schedules for determining settlement prices (known as "final prices") use some different inputs from other schedules. In particular, they use metered load quantities rather than bids or load forecasts. It is possible that settlement prices may be quite different from prices emerging from earlier schedules such as the NRS and RTD. The process of determining settlement prices also involves adjusting the inputs of the pricing schedule to resolve any infeasibilities.

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7 Refer to clauses 5 and 6 of Technical Code B of Schedule 8.3 of the Code.

8 If the load curtailment occurs over a number of trading periods, the load curtailment may get picked up in NRSs for those latter trading periods, depending on the way in which the load forecast uses recent load to forecast forward. Consequently, it is possible that a dispatch-NRS may reflect "easy" market conditions with lower prices (and dispatch DCLS load on) simply because other load is being curtailed.

2.1.23 If a resolved infeasibility in a pricing schedule was due to a shortage of reserves, the pricing process involves adding virtual reserve to the pricing schedule (that is, allowing the pricing schedule to solve with reduced physical reserve) until reserve prices do not exceed the higher of:

(a) three times the highest scheduled energy offer price

(b) the highest-priced reserve offer scheduled of the reserve product that is short.

2.1.24 If an island-wide (or national) shortage situation is declared by the system operator (refer to paragraph 2.1.20(b) above) and there are no binding constraints in the island (or nationally), the pricing manager can declare that a scarcity pricing situation exists. In this case, prices in the island (or nationally) will be scaled if necessary until the generation weighted average price is between $10,000/MWh and $20,000/MWh. A stop-loss provision limits average prices over a week to $1,000/MWh.[9]

The cost to the whole electricity system of near real time alternatives

Cost of mandatory load curtailment

2.1.25 One of the near real time alternatives to dispatching off high value DCLS load is to direct mandatory load curtailment. The cost of mandatory load curtailment is commonly referred to as the Value of Lost Load (VoLL). Some guidance as to an appropriate value can be obtained from the existing Code. The Code specifies a value of expected unserved energy (VEUE) of $20,000/MWh for the purposes of the grid reliability standards.[10] This also matches the upper limit of generation weighted average prices during scarcity pricing conditions.

2.1.26 During 2013, the Authority published a report titled *Investigation into the Value of Lost Load in New Zealand – Report on methodology and key findings* (23 July 2013).[11] The report examined the value of lost load for outages of 10 minutes, 1 hour, and 8 hours. The 1 hour values are probably the most relevant for the purpose of considering the cost of mandatory load curtailment as an alternative to dispatching off DCLS load in a half hour schedule. The report indicates that non-residential VoLL values generally exceed residential VoLL values. Since mandatory load curtailments implemented by distributors could be directed more towards residential load, the residential figures are likely to be most relevant. The report indicates that a residential customer's estimated "willingness to accept" a single 1 hour outage at 5pm on a winter evening is $69.34 per

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9 Refer to clauses 135A, 135B and 135C of part 13 and to clause 3 of schedule 13.3A of the Code

10 Clause 4 of Schedule 12.2 sets VEUE at $20,000/MWh or such other value as the Authority may determine.

11 Refer to http://www.ea.govt.nz/development/work-programme/transmission-distribution/investigation-of-the-value-of-lost-load/development/.

hour.[12] If each household is consuming 4 kW at the time, 1 MWh of energy savings can be achieved by cutting load to 250 residential connections. This equates to a VoLL of $17,335/MWh, which, when rounded, is quite close to the figure of $20,000/MWh mentioned in paragraph 2.1.25 above.

Cost of reducing reserves

2.1.27 Another near real time alternative is to operate on reduced reserves. The expected cost to the electricity system of this action can be evaluated as a small risk of a large cost being incurred (eg, AUFLS being triggered). As operating reserves are reduced further, the cost to the electricity system is likely to increase exponentially as a much greater range of outages could cause an AUFLS trip.

Cost of directing mandatory load curtailment or reducing reserves

2.1.28 If the system operator believes there will shortly be a shortage of dispatchable resources to meet system needs, it can choose whether to direct mandatory load curtailment or to reduce reserves. There is a range of possible costs this action could give rise to. For the purpose of the cost benefit analysis, we have modelled the cost as random between $7,000/MWh and $25,000/MWh.

2.1.29 The lower end of that range captures the idea that reasonably low-cost reductions in reserve might be available to the system operator. The higher end of the range captures the idea that mandatory load curtailment might be directed, and that the true cost may be a little higher than the indications given in paragraphs 2.1.25 and 2.1.26. Refer to the cost-benefit analysis in section 3.3 for more details.

Cost of late voluntary response

2.1.30 A lot of voluntary response may have occurred prior to the running of the dispatch-NRS in response to earlier forecast schedules. *Late* voluntary response is *additional* response that occurs after the running of the dispatch-NRS. The design of dispatchable demand arrangements should consider the possibility that no late voluntary response occurs. However, if it does occur, the Authority considers it is likely to have a cost lower than the range mentioned in paragraph 2.1.28 above. Refer to the cost-benefit analysis in section 3.3 for more details.

The NRS contributes to managing tight market conditions by dispatching dispatch bids

2.1.31 Having looked at how the system operator manages tight market conditions near real time and how this can be reflected in settlement prices, we can now examine how dispatchable demand contributes to managing tight market conditions.

[12] Refer to table 41 (yellow cells) from the report.

2.1.32 Different load inputs feed into the NRS for different types of load. Dispatch bids are used as an input where they are provided by a DCLS. Otherwise the input will be either the sum of the non-dispatch bid quantities or the system operator’s load forecast (depending on whether the GXP is classified as “non-conforming” or “conforming”).

2.1.33 We can think of the dispatch-NRS as having available to it a stack of energy offers and dispatch bids, stacked in order of the price associated with them.[13] As conditions get tighter the dispatch-NRS will “move up the stack”, scheduling increasingly expensive resources. This involves either scheduling *on* generation from an offer band or scheduling *off* load from a dispatch bid band. The scheduled quantities for dispatch bids in the dispatch-NRS are regarded under the Code as dispatch instructions.

2.1.34 Often a DCLS will have some load that it can switch on or off depending on price, and some load that might (somewhat loosely) be referred to as “must run” load. This must run load has a very high value to the DCLS. The dispatchable demand participant for the DCLS will typically bid that load in a bid band with a very high price. The bid band price may be the dispatchable demand participant's genuine estimate of the value of the DCLS’s load, or it might be an “arbitrary high number” intended to encourage the dispatch-NRS to dispatch that load on.

2.1.35 When market conditions in the dispatch-NRS get tight, the dispatch-NRS schedule will tend to dispatch off all dispatch bid bands before it schedules virtual reserve or virtual generation. This is because even the highest priced bid bands are typically below the CVPs. In the extreme case where the dispatch-NRS has no physically feasible solution and additional load can be met only by the scheduling of virtual resources, the dispatch-NRS will dispatch off *all* the relevant DCLS’s dispatch bid bands.[14]

2.1.36 Dispatching off all a DCLS’s dispatch bid bands may not be an efficient dispatch solution. Suppose that the dispatchable demand participant for the DCLS genuinely estimates the value of the first 5 MW of load is (say) $30,000/MWh and signals that in its dispatch bid. Suppose that mandatory load curtailment has a cost of $20,000/MWh. The dispatch-NRS would dispatch off that 5 MW DCLS bid band even though the market as a whole would in fact obtain greater benefit from allowing the DCLS to use that 5 MW and directing mandatory load curtailment.

2.1.37 There are three ways the dispatchable demand participant for the DCLS could attempt to keep this 5 MW load operating to achieve an efficient outcome:

[13] This way of imagining the workings of the NRS ignores transmission issues and interactions with reserves.

[14] It is possible for the dispatch-NRS to be physically infeasible and for a DCLS dispatch bid band to be dispatched on. The infeasibility may arise in relation to a node or region separate from where the DCLS is located. If additional load at the DCLS’s node can be met by dispatching additional physical generation, then one or more dispatch bid bands for that DCLS may well be dispatched on.

(a) ***Define the DCLS to not include this load:*** When a purchaser is seeking approval to operate a certain load as a DCLS, it must define the device or group of devices that are included within the DCLS. The DCLS must be separately metered. If any very high value load is associated with particular devices (eg, lighting or power to a control room), the purchaser could choose not to include those devices within the DCLS. The high value load, being outside the DCLS, would not be subject to dispatch in the dispatch-NRS and could remain on even during the tightest market conditions (subject to any grid emergency directions, operation of AUFLS, etc).

(b) ***Make the bid non-dispatchable:*** The dispatchable demand participant for a DCLS can choose, for each trading period, whether its bid is dispatchable or non-dispatchable. If it chooses to make the bid non-dispatchable, it would be able to self-schedule load on even during the tightest market conditions (subject to any grid emergency directions, operation of AUFLS, etc). The dispatchable demand participant for the DCLS could make its bid non-dispatchable whenever tight market conditions are forecast. While this would largely avoid the problem of the must run load being dispatched off, it would also remove the benefits of the dispatchable demand regime during tight market conditions which is when the regime would appear to have especially significant value.

(c) ***Price the must run bid band above CVPs:*** If the must run bid band is priced above the CVPs (above the critical generation deficit CVP of $500,000/MWh), the dispatch-NRS would dispatch that bid band on even during the tightest market conditions. The concern with this approach is that the whole “CVP regime” was designed under the assumption that the CVPs would be higher than any offer band or bid band price.

2.2 Analysis of potential policy problems

Potential policy problem with inefficient dispatch of dispatch bids during tight dispatch-NRS conditions

2.2.1 The discussion above has revealed a potential policy problem that the dispatch-NRS can dispatch off bid bands when the bid band is priced above the cost of near real time alternatives, such as operating with reduced reserves or directing real time load curtailment.

2.2.2 This inefficient dispatch can create very large constrained off payments to dispatchable demand participant for DCLSs, which must be paid by all purchasers. These payments are described in the next section.

Large constrained off payments possible when high value load dispatched off

2.2.3 A constrained off situation can arise for a DCLS when the dispatch instruction from the dispatch-NRS is for a lower quantity than in the schedule of final prices.[15]

2.2.4 In those situations a constrained off amount becomes payable to the relevant dispatch purchaser. This payment is funded by all spot market purchasers in proportion to their purchases.

2.2.5 The constrained off amount for a particular bid band is calculated as follows:

$$\text{Constrained Off Amount (in \$)} = \text{Constrained Off Quantity (in MWh)} \times \text{Price Difference (in \$/MWh)}$$

Where

$$\text{Constrained Off Quantity (in MWh)} = \text{Quantity Scheduled in Final Pricing for that Bid Band (in MWh)} - \text{Max}\left(\text{Quantity Dispatched for that Bid Band (in MWh)}, \text{Reconciled Metered Quantity for that Bid Band (in MWh)}\right)$$

and

$$\text{Price Difference (in \$/MWh)} = \text{Bid Band Price} - \text{Final Price at the Relevant Node}$$

2.2.6 These constrained off payments could be very large when high value bid bands are dispatched off. Suppose a DCLS bids 30 MW of “must run” load at $80,000/MWh which gets dispatched off for one trading period by the dispatch-NRS. If the final price at the node ends up being $500/MWh (for any of a variety of reasons), then the constrained off amount for the trading period would be $1,192,500.[16]

Risk of poor market outcomes associated with dispatching off high value bids

2.2.7 There are substantial risks in dispatching off high value “must run” DCLS load 25 minutes ahead of real time, especially where the bid prices are in the region from $15,000/MWh up to $100,000/MWh:

(a) If market conditions subsequently change prior to real time (eg, late voluntary response occurs, a bona fide generator outage finishes

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15 Refer to clause 13.192 of the Code.

16 This assumes the DCLS complies with its zero dispatch instruction. The calculation is 0.5 (since the trading period is half an hour) * 30 MW * ($80,000 - $500) = $1,192,500.

early), the turning off of the DCLS's must run load may turn out to have been highly inefficient.

(b) Even if real time market conditions turn out to be very tight, cheaper near real time alternatives may be available. Mandatory load curtailment might be achievable through distributors at a substantially lower cost. Alternatively, the cost to the system of operating with reduced reserves may be less than the lost value of the DCLS's must run load. If the DCLS load is valued well above $15,000/MWh, the dispatch could be highly inefficient.

2.2.8 In addition, there are concerns created by the potential market effects of bids in the region from $15,000/MWh up to $100,000/MWh as they could set prices across the whole country at those levels. Not only might this be inefficient (if the true system marginal cost is lower because cheaper alternatives are available), but those high prices may result in very large wealth transfers between participants that are not perfectly hedged. Perfect hedging can be difficult (costly) for participants to achieve. It may be unrealistic and inefficient for each participant to devote resources to managing the financial risks associated with prices at those levels.

2.2.9 Even if final prices turn out to be set at lower levels, significant wealth transfers may occur from purchasers in general who fund constrained off payments to the dispatchable demand participant of the DCLS that receives such payments.

Don't similar problems emerge for generator offers in this range?

2.2.10 This paper has identified a potential policy problem with inefficient dispatch of bids during tight market conditions. But isn't there also a similar problem with high value generator offers? Why would the Authority propose to resolve the problem for bids but not resolve the problem for offers (and reserve offers)?

2.2.11 The equivalent generation problem would arguably arise if a generator offer band in the range from $15,000/MWh to $100,000/MWh was dispatched *on* in circumstances where this was more costly than mandatory load curtailment or reducing reserves. This would be inefficient. In addition, substantial wealth transfers could result if settlement prices were set by such offers. If final prices turned out to be at more normal levels, large constrained *on* payments could result. Such payments would be funded by purchasers.

2.2.12 Several factors combine to mean that, while it is possible for generator offers to create an equivalent policy problem, the problem is less likely to occur and, if it does occur, is likely to be less severe in its consequences.

2.2.13 First, it may be less likely that generator offer band prices will lie in the region between $15,000/MWh and $100,000/MWh. Clause 13.5A(1) of the Code (inserted on 17 July 2014) provides that each generator and ancillary service agent must ensure that its conduct in relation to offers and reserve offers is consistent with a high standard of trading conduct. This clause applies to generators but not to DCLSs. It may act to reduce the incidence of offer band prices in the range above $15,000/MWh.

2.2.14 It is very uncommon to observe a generator offer band in excess of $12,000/MWh. From the beginning of 2012 to 27 August 2015, there have been only three occasions on which offer bands have been submitted above $12,000/MWh:

(a) On 14 November 2013 for trading period 17, Genesis Energy Limited (Genesis) revised its offers for the Waikaremoana Hydro Scheme at TUI1101 (the Kaitawa, Tuai and Piripaua hydro stations) just before gate closure so that the final three offer bands for each station were priced at $65,000, $68,000, and $70,000/MWh respectively. The final energy price at TUI1101 for that trading period was $96.94/MWh.

(b) On 31 October 2012 for trading period 15, Mighty River Power Limited offered a band of generation from the Arapuni hydro station priced at ARI1101 and ARI1102 at $30,000/MWh. The final energy price at ARI1101 for that trading period was $46.68/MWh.

(c) On 22 May 2012 for trading period 25, Genesis offered a band of generation at Huntly at $23,002/MWh. The final energy price at HLY2201 for that trading period was $183.41/MWh.

2.2.15 A generator that wants *not to generate* from an offer band can either price the offer band very high or, more commonly, not offer that band at all. The latter option gives it “certain self-dispatch” at zero for that band. The dispatchable demand participant submitting a dispatch bid that (equivalently) *wants to use load* from a bid band can price that load high to make dispatch of that load likely, but does not have a similar “certain self-dispatch” alternative to ensure the load is dispatched on. Consequently high priced dispatch bids bands may appear more frequently than high priced generation offers.

2.2.16 This argument is mitigated by the fact there is currently only one dispatchable demand participant submitting dispatch bids. Dispatch bids were submitted for two DCLS for the four days beginning 20 November 2014 (both operated by Norske Skog at KAW0112 and KAW0113 respectively), but since 24 November 2014 only the DCLS at KAW0113 has been submitting dispatch bids. The highest priced bid band at that location has consistently been priced at $5,000/MWh since that date. However, in the four days beginning 20 November 2014 its highest priced bid band was set at $50,000/MWh, while the DCLS at KAW0112 consistently submitted a bid band with a price of $200,000/MWh.

2.2.17 So even though there are not many approved DCLSs, dispatch bid bands with prices over $15,000/MWh have been submitted for 192 trading periods (4 days * 48 trading periods) over a 9 month period. Although current bidding practices avoid such high bid prices, there is no guarantee such high bid prices will not arise again in the near future.

2.2.18 A second factor reducing the equivalent problem with respect to generator offers is that generation is dispatched from RTD rather than the dispatch-NRS schedule. This has two important implications:

(a) ***RTD incorporates near real time actions***: RTD schedule is normally run every 5 minutes and aims to manage the power system over the following 5 minutes. Multiple RTD runs are carried out during each half hour trading period. After DCLSs are dispatched from the dispatch-NRS, late voluntary response may occur, and/or the system operator may direct mandatory load curtailment. These load reductions will result in easier market conditions in subsequent RTD runs. The generator offer band is therefore less likely to be dispatched on (compared with an equivalent DCLS bid band being dispatched off).

(b) ***RTD is likely to be closer to the final pricing schedule***: RTD runs much closer to real time than the dispatch-NRS which normally solves 25 minutes before the start of the relevant trading period. The inputs used for RTD, especially generation offers, reserve offers and estimates of load, are likely to be closer (than the dispatch-NRS) to the information used as an input into the final pricing schedule. For example, suppose a large generator comes back into service earlier than expected after experiencing an unexpected outage. Suppose the generator revises its offer 20 minutes before the start of the trading period to offer substantially more generation. This could completely eliminate the tight market conditions that occurred in the dispatch-NRS. Again, the generator offer band is less likely to be dispatched on (compared with an equivalent DCLS bid band being dispatched off).

2.2.19 Dispatch from RTD means the problem is less likely to occur and, if it does occur, is likely to be less severe. While there is no guarantee that a significant problem of this kind will not appear, it seems appropriate to address the problem with respect to dispatch bids without necessarily addressing the equivalent problem for offers. This is particularly the case because additional complications may arise if a solution is required that addresses the problem for both DCLSs and generators (and for reserve providers).

2.3 Summary of the problems with existing arrangements

2.3.1 The Authority has identified three policy problems that could occur when conditions in the dispatch-NRS are very “tight” – that is, when there is insufficient, or close to insufficient, generation and reserves to meet load and reserve requirements:

(a) ***Inefficient dispatch***: Inefficient dispatch can occur for high value dispatch bid bands. In particular that high value load can be dispatched off when it would have been possible to achieve greater overall sector benefits by: dispatching the load on, waiting to see if late voluntary response occurs and, if it does not, either directing mandatory load curtailment or implementing reduced reserves.

(b) ***Market prices above genuine scarcity levels***: It is possible for very high market prices (eg, $50,000/MWh) to occur which are substantially above levels that reflect marginal system costs during scarcity conditions. Such prices could cause large wealth transfers, which in turn create costs for participants trying to manage these risks, and undermine participants' confidence in the wholesale market.

(c) ***Constrained off payments***: (This can be viewed as a symptom of the first problem.) Large constrained off payments can occur in relation to very high value dispatch bid bands due to the inefficient dispatch of those bid bands. This creates incentives for inefficient behaviour by dispatchable demand participants that are directed towards capturing those payments.

Question 1	Do you agree with the Authority’s description of the problems with the existing arrangements?

2.4 Why the Authority is addressing these issues now

2.4.1 The Authority considers there is the potential that inefficient dispatch of high value DCLS load could occur during tight dispatch-NRS conditions. There is the potential for these inefficiencies to be quite substantial.

2.4.2 In addition, there is the potential for prices during tight market conditions to be set by dispatch bids at values between $15,000/MWh and $100,000/MWh over large regions or across the whole country if:

(a) further DCLSs are approved; or

(b) if existing dispatchable demand participants for DCLSs change their bidding practices.

2.4.3 This would result in large wealth transfers and could cause a loss of confidence in the existing market design.

Question 2	Do you agree the problems are of a sufficient magnitude to justify the Authority taking steps to resolve them?

3. Regulatory Statement for the proposed Code amendment

3.1 Objectives of the proposed Code amendment

3.1.1 The objectives of the proposed Code amendment are:

(a) to promote efficient dispatch of high value dispatch bid bands, recognising that there are near real time alternatives to dispatching off this load

(b) to allow a dispatchable load to signal that it has some “must run” load without having the risk that this will set market prices at values exceeding the cost of real time alternatives

(c) to ensure that constrained off payments are not made to DCLSs (funded by purchasers) based on very high bid prices exceeding the cost of near real time alternatives.

Question 3	Do you agree with the objectives of the proposed amendment? If not, why not?

3.2 The proposed Code amendment

3.2.1 The Authority is proposing to amend Part 13 of the Code to provide that a dispatchable demand purchaser for a DCLS must price dispatch bid bands at or below $15,000/MWh or at $600,000/MWh (that is, above the level of the CVPs).

Effect of the proposal

3.2.2 The effect of the proposal will be as follows:

(a) ***Where a dispatch bid band is priced below $15,000/MWh***: The bid band will be dispatched off during very tight dispatch-NRS conditions. It is efficient for low value dispatch bid bands to be dispatched off in preference to risking the need for expensive mandatory load curtailment or operating on reduced reserves.

(b) ***Where a dispatch bid band is priced at $600,000/MWh***: The bid band will not be dispatched off by the dispatch-NRS in any circumstances (even if the schedule is infeasible). Final pricing will never set the price at $600,000/MWh because this value is above the generation deficit CVP of $500,000/MWh. The final pricing optimisation engine would choose to schedule virtual generation (an infeasibility) before scheduling off the bid band. When infeasibilities are resolved in final pricing, the price will be set at a level below the CVPs by using physical bids/offers.

Justification for the $15,000/MWh figure

3.2.3 The exact value used as the bid “cap” ($15,000/MWh in the proposal) may not be particularly important in practice. In practice, a DCLS bid band is likely to be valued either much higher or much lower than that figure.

3.2.4 The cap could alternatively be set at a value of $20,000/MWh. This would match the value of expected unserved energy (VEUE) used for the grid reliability standards (refer to clause 4 of Schedule 12.2 of the Code) and the upper limit for generation-weighted average prices during scarcity pricing (refer to clause 3 of schedule 13.3A of the Code). However, paragraph 2.1.26 above indicated a slightly lower figure of $17,335/MWh might be an appropriate value for mandatory load curtailment.

3.2.5 A figure lower than those mentioned in paragraph 3.2.4 could be justified on the grounds that there is a chance that late voluntary response may occur at a much lower cost. To illustrate: it would not be efficient to dispatch off a DCLS bid band priced at $20,000/MWh when there is a chance that lower cost late voluntary response could occur, and when (even if that voluntary response doesn’t occur) there is mandatory load curtailment available at a similar cost of $20,000/MWh.

3.2.6 A lower cap of perhaps $10,000/MWh might be justifiable if more significance is attached to the chance of late voluntary response occurring at a low cost. However, this may not yield any substantial difference in practical outcomes. At present the dispatch-NRS is normally completed 25 minutes before the start of the trading period, but there is nothing in the Code preventing the system operator from running this schedule closer to the trading period. That would provide less time for late voluntary response and make a lower cap less appropriate. In theory a bid cap of $10,000/MWh could result in DCLS load valued at $14,000/MWh being dispatched on while mandatory load curtailment at a cost of $20,000/MWh is occurring.

There are no negative unintended consequences

3.2.7 The Authority asked the system operator to confirm that, if dispatch bid bands were submitted with prices above the CVPs, whether this could have any negative unintended consequences such as creating the possibility that final prices could be set at those values.

3.2.8 The system operator’s report is attached as Appendix C. It notes that:

The SO advises bidding DD at $600,000/MWh is sufficiently high to ensure load bid at that price will not be dispatched off. Equally the SO believes bids submitted at $600,000/MWh will not cause any undue price results in the market schedules.

3.3 The proposed Code amendment's benefits are expected to outweigh the costs

Benefits

3.3.1 The economic benefits of the proposed Code amendment are:

Static efficiency benefits

(a) *Avoiding the curtailment of high value dispatchable load when lower cost near real time alternatives are available:* At present, dispatchable load with a value greater than near real time alternatives could be dispatched off in the dispatch-NRS before the near real time alternatives can be considered.

The present value of this benefit is estimated to be $1.51 million. This is derived from a flow of benefits of $229,500 per year for 8 years with a discount rate of 6 percent.

The annual benefit flow of $229,500 is derived assuming:

(i) That there are 2 trading periods per year in which a choice needs to be made between dispatching "must run" DCLS load off or using near real time alternatives. This figure is an estimate of the likely long run equilibrium figure. There may be fewer such trading periods during years where demand growth is low, and more where demand growth is high.

(ii) On each occasion there is 9 MW of must run DCLS load that could be dispatched off. This equates to 4.5 MWh of load in each trading period.

(iii) The average efficiency improvement (measured in $/MWh) from the proposal is $25,500/MWh. This figure is obtained by assuming:

A. **A distribution for the value of the DCLS must run load**: The Authority has assumed the value of the DCLS must run load is distributed reasonably evenly between $17,000 and $50,000/MWh, with an average of $33,500/MWh. Ten values are identified in this range, each with an equal probability, giving ten "scenarios" in the cost-benefit analysis.

B. **A distribution for the cost of mandatory load curtailment and reduced reserves**: The Authority has assumed the cost of mandatory load curtailment or reduced reserves (whichever option is chosen by the system operator) is distributed evenly between $7000/MWh and $25,000/MWh with an average of $16,000/MWh. Ten values are identified in this range, each with an equal probability. This gives 10 "scenarios" which, when combined with the ten scenarios in paragraph A above, gives 100 scenarios.

C. **Probability that late voluntary response is available**: This is estimated for the purpose of the cost-benefit analysis as a 50 per cent likelihood. The two "scenarios" (late voluntary response occurs or it does not), when combined with the previous 100 scenarios, produces 200 scenarios.

D. **Cost of any late voluntary response**: This is estimated for the purpose of the cost-benefit analysis as $5000/MWh.

In each scenario we determine whether the DCLS would be dispatched on or off under the status quo. We assume that, under the status quo, the DCLS must run load is always dispatched off in these scenarios. We determine the cost of the lost load, including the cost of any late voluntary response. The average cost is $36,000/MWh.

Then we carry out the same process for the proposal.[17] Under the proposal, the DCLS's must run load would be dispatched on in all scenarios. The average cost is $10,500/MWh.

The efficiency gain is determined as the reduction in cost between the status quo and the proposal, which is $25,500/MWh.

Note that 2 trading periods per year * 4.5 MWh in each trading period * efficiency savings of $25,500/MWh = $229,500 per year.

This analysis also assumes there will continue to be one participating DCLS load for the next eight years. If additional loads join as DCLSs, the benefits are likely to be higher. If the existing active DCLS withdraws its participation, the benefits would be less.

Dynamic efficiency benefits

(b) *Increasing participant and public confidence in the wholesale electricity market.* Under the status quo, it is possible that a DCLS dispatched bid at (say) $50,000/MWh could set the price at $50,000/MWh across the country. This price is unlikely to represent genuine marginal system costs since mandatory load curtailment can probably be achieved at a lower cost. This high price is likely to result in very substantial wealth transfers between participants who are not perfectly hedged. It is not practical to expect market participants to manage such risks.

[17] We assume that, under the proposal, if the value of DCLS load is up to $20,000/MWh it is bid at that value, and if the DCLS load value is higher than $20,000/MWh it is bid at $600,000/MWh.

The Authority has not quantified this benefit. At the end of the analysis we adopt an approach that asks “what would we have to believe” about the size of these benefits to justify progressing the proposal over the status quo?

Costs

3.3.2 The costs associated with implementing this proposal are made up of service provider costs and the administrative costs to the Authority of progressing the proposed Code change and communicating the effects to DCLSs.

3.3.3 The service provider for the wholesale information and trading system (WITS) has provided a high level estimate of $10,000 for changes to the WITS system. There are no other expected service provider costs.

3.3.4 The Authority’s administrative costs (assessed from the point in time after submissions on this consultation paper have been received and analysed) are estimated at $20,000, giving a total estimated cost of implementing the proposal of $30,000.

Benefits likely to exceed costs

3.3.5 The expected net present value of the proposal compared with the status quo (but excluding any dynamic efficiency benefits) is $1.48 million. The Authority believes the benefits of the proposal (compared with the status quo) are likely to exceed the costs, even if the dynamic efficiency benefits were assessed at zero.

Question 4	Do you agree the benefits of the proposed amendment outweigh its costs? If not, why not?

3.4 The Authority has identified five alternative options for addressing the objectives sought by this proposed amendment

3.4.1 The Authority has identified five alternative options for addressing the objectives sought by this amendment:

(a) **Alternative A – Bid cap of $20,000/MWh:** This alternative is the same as the proposal except that the "bid cap" is $20,000/MWh rather than $15,000/MWh.

(b) **Alternative B – Ceiling on constrained on/off amounts:** This alternative aims to address the problem of large constrained off amounts becoming payable when the dispatch-NRS is very tight (or infeasible). If a high value dispatch bid band was dispatched off, the bid band would not be eligible to receive constrained off payments at a rate higher than a particular level: say $15,000/MWh.

(c) **Alternative C – Suspend the dispatchable demand regime when conditions are tight:** When the dispatch-NRS is so tight that dispatch bid bands with prices in excess of some value (say $15,000/MWh) are being scheduled/dispatched off, amend the schedule inputs so that all bids are treated as non-dispatchable. Then there would be no dispatch instructions to a DCLS, so it could self-dispatch at a level it considers appropriate. There would be no constrained on/off payments to the DCLS for that trading period. The DCLS bid could not set prices.

(d) **Alternative D – Must run load separately metered:** The DCLS's "must run" load would be separately metered so could be excluded from the definition of the DCLS. The must run load would not be subject to a dispatch instruction, but other DCLS load could be subject to a dispatch instruction.

(e) **Alternative E – Run a second dispatch-NRS in the trading period:** This option could be considered either as an alternative, or as a complement to the options listed above. This option would involve running a second dispatch-NRS late in the trading period to ensure the latest information is used in the DCLS dispatch. If any of the inputs to the dispatch-NRS had been revised since the dispatch-NRS had been run they would be picked up by this second run and may assist in alleviating the tight market conditions and may revise DCLS dispatch instructions. Changes that may assist in alleviating the tight market conditions would be increased offers, increased instantaneous reserve offers, revised dispatch bids or revised grid information. There are two possible variations on this option:

(i) Run a second dispatch-NRS every trading period.

(ii) Run a second dispatch-NRS in the trading period if a "trigger" is met. That trigger could be if a price at a DCLS node exceeds, say, $10,000/MWh in the first dispatch-NRS.

3.5 The proposed Code amendment is preferred to other alternative options

3.5.1 The Authority has evaluated the other means for addressing the objectives and prefers the proposed Code amendment for the reasons provided below.

Alternative A – Bid cap of $20,000/MWh

3.5.2 The Authority considers that Alternative A would produce lower benefits than the proposal. The difference between Alternative A and the proposal is that, under Alternative A the DCLS load will be dispatched off if it is valued (and bid) between \$15,000/MWh and \$20,000/MWh. However, it seems unlikely that dispatching off a bid band 25 minutes before the beginning of the trading period would be efficient. If cheap late voluntary response subsequently occurs, the decision to dispatch off the DCLS will produce a higher overall system cost than if it had been dispatched on for its must run load.

3.5.3 While the benefits of Alternative A are lower than for the proposal, the costs are identical. Overall, Alternative A is assessed as delivering a lower present value of net benefits.

Alternative B – Ceiling on constrained on/off amounts

3.5.4 Alternative B would avoid very high constrained on/off payments but would not solve the primary policy problem that high value dispatch bid bands would be dispatched off when there are lower cost real time alternatives available. The principle benefits of the proposal (the static benefits assessed at \$1.51 million) would not be captured.

3.5.5 There would also likely be some cost (probably relatively minor) associated with the clearing manager amending its systems for calculating constrained on/off amounts.

Alternative C – Suspend the dispatchable demand regime when conditions are tight

3.5.6 Under Alternative C we assume the DCLS self-dispatches on in all 200 scenarios described in 3.3.1 (the same as for the proposal). The average cost across all scenarios under Alternative C is \$10,500/MWh (again, the same as for the proposal). Consequently, Alternative C will deliver broadly the same level of benefits as the proposal.

3.5.7 It is possible that some factors not modelled above may reduce the benefits of Alternative C below those of the proposal. Alternative C does not allow other dispatch bid bands to be dispatched using SPD, but requires that they too be self-dispatched. This could result in some inefficient dispatch of those price-responsive bid bands.

3.5.8 Also, under Alternative C the information from DCLS price-responsive dispatch bid bands will not be used to determine final prices. This may reduce the “information content” of final prices, potentially reducing their effectiveness in signalling marginal system costs.

3.5.9 The key argument against Alternative C is that it is likely to have much higher costs of implementation. An additional process would need to be built into the scheduling process to identify whether conditions are tight enough to justify suspending the dispatchable demand regime by treating bids as non-dispatchable. If conditions are identified as sufficiently tight, a process would be required to treat those bids as non-dispatchable in the dispatch-NRS, in final pricing, and in the calculation of constrained on/off amounts.

3.5.10 The Authority has not sought a price for this work from the system operator, but similar kinds of changes have been valued at over $500,000.

3.5.11 Given that Alternative C would require significant changes to the system operator's scheduling systems, it would clearly deliver lower benefits than the proposal.

Alternative D – Must run load separately metered

3.5.12 As for Alternative C, this approach would result in the must run load being dispatched on in all 200 scenarios. Consequently, it would produce the same modelled benefits as the proposal.

3.5.13 However, it would have a higher cost because each DCLS would have to install separate metering on its must run load, including a system for communicating the metering information to the system operator. It is not clear what the cost of this would be, but it may be in the tens of thousands of dollars for each DCLS.

3.5.14 In addition, Alternative D assumes that the must run load is on separate *machines* from other load. This is probably the case for the existing dispatchable demand participants. However, there is no guarantee that future dispatchable demand participants would have their must run load on separate machines. It is possible that a single machine has to run at some minimal level (must run load) but can increase its use of electricity if electricity market conditions warrant. In this case, the requirement to separately meter the must run load would be difficult to implement.

3.5.15 The Authority considers that Alternative D could capture broadly similar benefits to the proposal, but it is likely to have a higher cost.

Alternative E – Run a second dispatch-NRS in the trading period

3.5.16 The Authority considers that Alternative E alone or alternative E as a complement to other options should not be considered further because:

(a) it would be of limited benefit

(b) it would be difficult to operationalise

(c) it would be costly to implement.

3.5.17 These points are discussed further below.

Alternative E would be of limited benefit

3.5.18 Alternative E would allow any revised inputs to be incorporated into the dispatch-NRS late in a trading period. However, the benefits of enabling this would be limited because the Code places restrictions on the circumstances when offers and instantaneous reserve offers can be increased or decreased within the gate closure period. These restrictions are in place to provide a stable period before each trading period during which the system operator can assess system security. In addition, the restrictions limit the ability for market participants to change their offers and reserve offers at the last minute to manipulate spot prices.

3.5.19 The restrictions on offers and reserve offers are as follows:

(a) The Code allows generators and instantaneous reserve providers to submit offers for increased quantities after gate closure only when a grid emergency has been declared or when plant is returning to service earlier than expected following an outage that was for a bona fide physical reason.

(b) Reductions in offer quantities are allowed during the gate closure period, but only for very specific reasons. Any reductions would more than likely compound, not alleviate, the tight market conditions.

3.5.20 The circumstances that give rise to a grid emergency and plant returning to service are anticipated to be a small subset of the circumstances that may give rise to “tight” market conditions. Consequently, the Code restrictions described above are likely to significantly limit the benefit of Alternative E.

Alternative E would be difficult to operationalise

3.5.21 Another concern with Alternative E is that it would be difficult for the system operator to operationalise. This is because the system operator has confirmed that the NRS is the basis on which it manages real time security and ensures secure, economic dispatch. The fact that the NRS requires extensive security checks by the system operator’s real-time team means that they typically need 15 to 20 minutes to carry out these checks. Consequently, the preparation of a second NRS late in the trading period is difficult to implement in practise.

Alternative E would be costly to implement

3.5.22 To estimate the implementation cost of Alternative E the Authority makes reference to a previous cost estimate prepared for a different, but similar option. The similar option was considered by the Authority in the earlier consultation on dispatchable demand late bid revisions.[18] The similar option would continue to produce one dispatch-NRS per trading period, but that it would be produced close to the start of the trading period (rather than 25 minutes prior to the trading period as is currently the practice).

[18] Alternative D in the *Dispatchable demand - late bid revisions* consultation paper, which can be found at http://www.ea.govt.nz/development/work-programme/wholesale/operational-enhancements-to-dispatchable-demand/consultations/

3.5.23 The system operator's high level cost estimate to implement the similar option was $560,000. The system operator has since confirmed that the cost to implement either of the Alternative E variants (as described in 3.4.1(e)) is expected to be in the same order.

3.5.24 The cost of $560,000 would substantially reduce the net benefit of $1.48m described in 3.3.5 and be significantly greater than the estimated cost to implement the proposed amendment of $30,000 as described in 3.3.2.

Question 5	Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

3.6 The proposed Code amendment complies with section 32(1) of the Act

3.6.1 Table 1 (below) demonstrates how the proposal complies with section 32(1) of the Act.

Table 1: How proposal complies with section 32(1) of the Act

Requirement	Comment
The proposed amendment is consistent with the Authority's objective under section 15 of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.	The proposal promotes the efficient operation of the electricity industry by promoting efficient dispatch of high value dispatch bid bands.
The proposed amendment is necessary or desirable to promote any or all of the following:	
(a) competition in the electricity industry;	The proposal will not have any significant impact on competition.

(b) the reliable supply of electricity to consumers;	The proposal will not have any significant impact on promoting the reliable supply of electricity to consumers. In tight market conditions, the proposal influences whether load reductions are achieved by dispatching off a high value “must run” dispatch bid band, or by real time load curtailment (or a similar measure involving operating on reduced reserves). Either option involves switching off load in situations where reliability cannot be maintained. So the proposal does not promote reliability: rather it influences the allocation of curtailment between the high value dispatch bid bands, and other load that could be curtailed in real time under grid emergency provisions.
(c) the efficient operation of the electricity industry;	The proposal promotes the efficient operation of the electricity industry by promoting efficient dispatch of high value dispatch bid bands.
(d) the performance by the Authority of its functions;	The proposal does not affect the performance by the Authority of its functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposal does not affect these other matters.

Question 6	Do you agree the Authority’s proposed amendment complies with section 32(1) of the Act?

3.7 The Authority has given regard to the Code amendment principles

3.7.1 When considering amendments to the Code, the Authority is required by its consultation charter to have regard to the following Code amendment principles, to the extent that the Authority considers that they are applicable. [19] Table 2 (below) describes the Authority’s regard for the Code amendment principles in the preparation of the proposal.

[19] The consultation charter is one of the Authority’s foundation document and is available at: http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/

Table 2: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective (see section 3.6) and with the empowering provisions of the Act
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The efficiency gains are set out in the evaluation of the costs and benefits (section 3.3). The proposal will improve static efficiency primarily by achieving more efficient dispatch of high value dispatch bid bands. It will also improve dynamic efficiency. The proposal has relatively minor costs associated with it (there are no costs incurred by service providers). The Authority is confident that the benefits will exceed the costs.
3. Net benefits are quantified	The extent to which the Authority has been able to estimate the efficiency gains is set out in the evaluation of the costs and benefits (section 3.3).

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
AUFLS	Automatic under-frequency load shedding
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
CVP	Constraint violation penalty. There are several different CVPs, each with its own dollar value. They represent the cost of various non-physical (“virtual”) resources that SPD can schedule to reach a solution to its optimisation problem. The two key CVPs for the purposes of this paper are the $100,000 CVP for virtual FIR or SIR for a contingent event, and $500,000 for virtual generation.
DCLS	Dispatch-capable load station. A load that has registered with the Authority to participate in the dispatchable demand regime.
Dispatch-NRS	For a particular trading period the dispatch-NRS is the schedule relating to that trading period from the NRS that was run most recently during the previous trading period and which was used to prepare dispatch instructions for DCLSs
FIR	Fast instantaneous reserve
GXP	Grid exit point
MW	Megawatt
MWh	Megawatt-hour
NRS	Non-Response Schedule prepared under clause 13.62 of the Code. In this paper, NRS refers to the schedule that covers 8 trading periods and is (at present) run once every half hour (clause 13.62(1)(b)). The NRS that runs during a trading period determines dispatch instructions to DCLSs for the following trading period.
NRSS	Non-Response Schedule (Short), the common term for the NRS defined in clause 13.62(1)(b) of the Code.
RTD	Real time dispatch. This is the schedule used by the system operator to dispatch generation and reserves in real time
RTP	Real time pricing. This is the schedule published normally every 5 minutes to provide participants with a real time indication of likely settlement price levels

SIR	Sustained instantaneous reserve
SPD	The “Scheduling, Pricing and Dispatch” mathematical optimisation software that is used to create schedules in the wholesale electricity market
VEUE	Value of expected unserved energy
VoLL	Value of lost load

Appendix A Proposed Code amendment

The following amendments are proposed to Part 13 of the Electricity Industry Participation Code 2010.

13.13 Information to be contained in bids

(1) A **purchaser** must ensure that each of its **nominated bids**—

(a) contains all information required by Form 4 in Schedule 13.1; and

(aa) if it is a **nominated bid** for a **dispatch-capable load station**, specifies whether it is—

(i) a **nominated dispatch bid**; or

(ii) a **nominated non-dispatch bid**.

(b) *[Revoked]*

<u>(c) if it is a **nominated dispatch bid**, specifies a price for each band that is either—</u>

<u>(i) less than or equal to $15,000/**MWh**; or</u>

<u>(ii) equal to $600,000/**MWh**.</u>

Question 7	Do you have any comments on the drafting of the proposed amendment?

Appendix B Format for submissions

Submitter	

Question		Comment
Question 1	Do you agree with the Authority's description of the problems with the existing arrangements?	
Question 2	Do you agree the problems are of a sufficient magnitude to justify the Authority taking steps to resolve them?	
Question 3	Do you agree with the objectives of the proposed amendment? If not, why not?	
Question 4	Do you agree the benefits of the proposed amendment outweigh its costs? If not, why not?	
Question 5	Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Question 6	Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	
Question 7	Do you have any comments on the drafting of the proposed amendment?	

Appendix C System operator report - Dispatchable Demand bids in excess of Constraint Violation Penalty values