Implementing spot market settlement on real-time pricing

Decision

28 June 2019

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1 We have decided to settle the spot market on prices determined in real-time

1.1 The Electricity Authority (Authority) has decided to amend the Electricity Industry Participation Code (Code) to settle the spot market on prices determined in real-time. We call this ‘real-time pricing’ (RTP). The Code amendment attached as Appendix A implements RTP by:

(a) determining final spot prices from new ‘dispatch prices’ struck in real-time whenever the system operator issues dispatch instructions

(b) disestablishing the pricing manager role, as it will no longer be required

(c) applying scarcity pricing by default to all forecast demand, to ensure all demand has a price

(d) introducing new ‘risk-violation curves’ to handle shortfalls in instantaneous reserve

(e) revising the process for manually claiming a pricing error, reflecting the way spot prices will be determined under RTP

(f) fully integrating dispatchable demand into the system operator’s real-time dispatch process

(g) extending arrangements for dispatch to make it easier for both smaller-scale purchasers and generators to participate — we call this ‘dispatch-lite’.

1.2 RTP will be the largest change to the wholesale spot market since its inception in 1996. Moving to real-time prices makes the spot market simpler overall — prices will now be driven directly by live conditions on the power system, rather than calculated separately the next day using different information. This largely removes the current major cause of uncertainty about the price parties will pay or receive for the electricity they buy and sell in the wholesale spot market. Under RTP, the spot prices visible in real-time will be ‘actionable’: consumers and participants can trust and act on those prices with far greater confidence than today.

1.3 We expect RTP to unlock significant benefits, while helping ‘future proof’ the electricity market. Consumers and generators that can alter their operations at short notice will have much more reliable price signals to guide their actions. The spot market under RTP will far better support rapidly evolving technologies like battery storage and smart appliances, making it easier to capture the full potential of these innovations. Dispatch-‘lite’ brings further support by offering new opportunities to coordinate smaller-scale distributed resources through the system operator’s dispatch process. Even participants needing more time to react will benefit from prices they can see and rely on in real-time.

1.4 We will implement RTP in stages over the next four years. Once RTP goes live in late 2022, we expect it will produce net benefits with a present value of $50 million over 15 years in the base case. We also estimate net benefits in upper and lower cases of $95 million and $15 million, respectively. Our assessment of costs and benefits is detailed in section 9.

2 Our decision incorporates two rounds of consultation on our proposed design for RTP

2.1 In August 2017, we published a consultation paper titled, *Real-time pricing proposal* (our **2017 paper**).[1] We consulted on our proposal to amend the Code to determine wholesale spot prices in real-time, making them more actionable and more efficient. Our proposed design implemented the 'look-ahead, dispatch-based' form of RTP we decided to pursue in our earlier 2016 consultation.[2]

2.2 As set out in our 2017 paper, our proposal targets two problems with the way prices are determined in the wholesale electricity market today:

(a) Wholesale spot prices for energy and instantaneous reserve in each trading period are first calculated the day after real-time, using different inputs.[3] Final spot prices are not confirmed until at least two days after the fact.

(b) The spot prices published up to and during real-time are only indicative. These indicative prices are normally a sound guide to final prices, but large differences can arise — especially when the power system is under stress. Spot prices are therefore uncertain, making it harder for parties to make efficient real-time decisions about how much electricity they buy or sell.

2.3 RTP addresses these problems by instead determining spot prices through the dispatch process the system operator uses to run the power system in real-time. The system operator will produce 'dispatch prices' whenever they issue new dispatch instructions, typically every five minutes or so (and at least once for each 30-minute trading period). The final price for each node will then be the time-weighted average of the dispatch prices published and visible on the Wholesale Information and Trading System (WITS) for that trading period.

2.4 Using the system operator's dispatch process in this way will make spot prices more actionable and more efficient, because:

(a) participants will have information in real-time about the prices they will pay or receive for the energy and reserves they buy or sell — prices will be more certain

(b) dispatch prices will be derived from the marginal generator offer or dispatchable demand bid each time the system operator issues new dispatch instructions. Spot prices will now reflect what actually happens in real-time, rather than a more 'idealised' dispatch calculated in hindsight.

2.5 Our 2017 paper detailed the design elements we proposed to implement RTP, along with related elements that would strengthen the benefits we expect RTP will deliver. It included our initial proposal for a dispatchable demand 'lite', for smaller purchasers.

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1 Our August 2017 *Real-time pricing proposal* consultation paper is available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c16609.

2 Our August 2016 decision paper and April 2016 consultation paper on four options for implementing RTP are available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/exploring-refinements-to-the-spot-market/consultations/#c15922.

3 For example, final prices today are calculated using 30-minute averages of actual metered load.

2.6 On 19 March 2019, we published a follow-up consultation paper titled, *Remaining elements of real-time pricing* (our **2019 paper**).[4] We consulted on three particular design elements, partly in response to matters raised in submissions on our 2017 paper: an expanded form of 'dispatch-lite', now covering both smaller generators and smaller purchasers; using a 'risk-violation curve' to determine prices during shortfalls in instantaneous reserve; a process for setting the scarcity pricing values, and an obligation for the Authority to review those values at least once every five years.

2.7 This current paper sets out the Authority's decision to implement RTP. It gives reasons for that decision, covering matters raised in submissions to both our 2017 and 2019 papers. The enabling Code amendment is attached as Appendix A.

2.8 More information about the RTP project and all published material is available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/.

[4] Our 19 March 2019 *Remaining elements of real-time pricing* consultation paper is available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/?show=17972.

We considered submissions from the following parties in making our decision

2.9 Eighteen parties made submissions on our 2017 consultation, and 11 on our 2019 consultation. These parties are listed in Table 1. All submissions and a summary of submissions for both consultations are published on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/.

Table 1: List of submitters

Submitter	2017	2019	Role
Contact Energy Limited (Contact) Genesis Energy Limited (Genesis) Mercury Energy Limited (Mercury) Meridian Energy Limited (Meridian) Trustpower Limited	O O O O O	O O O O O	Large generator and retailer
Flick Energy Limited (Flick)	O		Smaller retailer
Independent Electricity Generators Association Incorporated (IEGA) New Zealand Wind Energy Association (WEA)	O	O O	Generator representative body
Electricity Networks Association (ENA) Orion New Zealand Limited (Orion) Powerco Limited Vector Limited	O O O O	O	Electricity distributor or representative body
Major Electricity Users' Group (MEUG) New Zealand Steel Limited (NZS) Pacific Aluminium New Zealand Limited Winstone Pulp International Limited (WPI)	O O O O	O	Consumer or representative body
NZX Limited (NZX)	O		Market system service provider
Transpower	O	O	Grid owner and system operator
EnerNOC Inc. (2017), now Enel X Australia Pty Limited (Enel X)	O	O	Load aggregator

3 To be actionable, the prices visible in real-time must always be 'real'

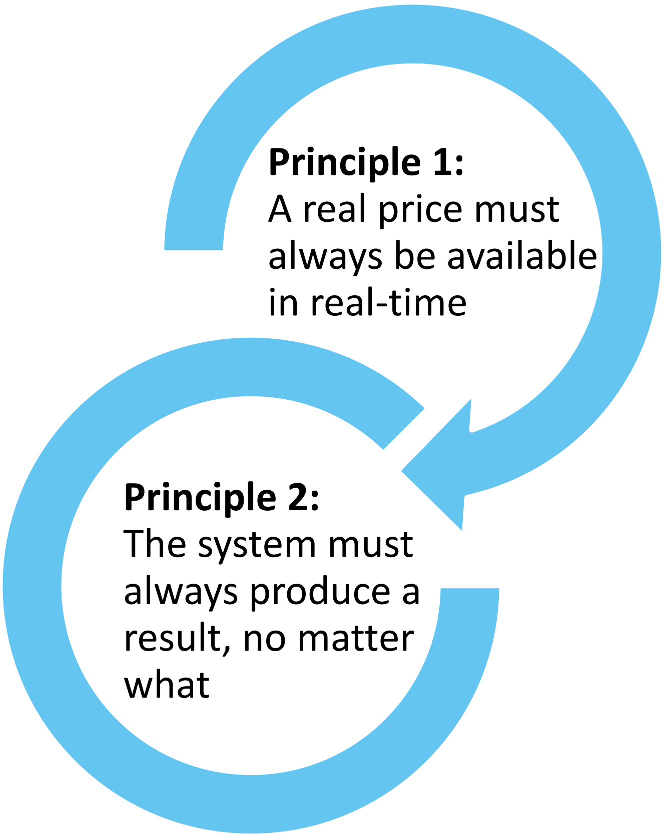
3.1 Delivering RTP's overarching objective of making spot prices actionable in real-time is a substantial design challenge. Scarcity pricing plays a vital role in achieving that goal. This section explains why, giving the broad structure for how we will implement RTP. The full details of our design are then set out in section 4.

Two design principles define RTP

3.2 The objective of actionable prices visible in real-time results in two fundamental principles for market design, shown in Figure 1. Together, these principles define RTP.

Figure 1: The fundamental design principles of RTP

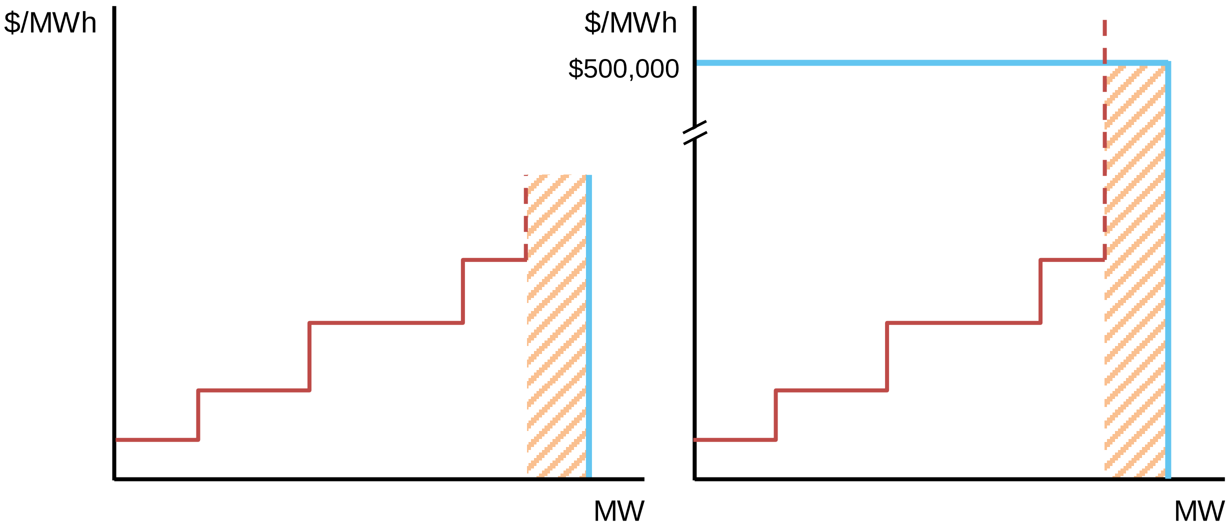
Principle 1 sets the goal. Principle 2 is the consequential requirement for system design.



3.3 But achieving these Principles is far from easy. It requires addressing an inherent mathematical problem: the system operator's scheduling, pricing, and dispatch system (SPD) cannot satisfy Principle 2 without managing demand when supply is limited. This is because while all offers specify a price for the MW quantities generators will supply, no price information exists for the vast majority of demand. The system operator forecasts demand at most GXPs; for the small number of GXPs where this is not possible, purchasers must nominate their expected demand quantities explicitly.[5] Only the prices specified in *dispatchable* demand bids are used for dispatch. The demand curve is then 'incomplete' — most of the MW quantity has no price assigned. SPD therefore cannot solve if generation offers are insufficient to supply total demand.

3.4 Today, the wholesale market handles this problem by using extremely high dummy price values to complete the demand curve, as shown in simplified form in Figure 2. SPD can then find a dispatch solution during a shortfall in generation (meeting Principle 2), but the resulting spot prices are not 'real' (failing Principle 1). In real-time, the system operator will intervene to instruct emergency load shedding if a shortfall occurs. This forces actual demand on the power system to fall to meet available supply. Scarcity pricing would then be applied manually when calculating spot prices separately the next business day, if the shortfall occurred across an island or nationally.[6] However, if the shortfall was less widespread, spot prices are suppressed by calculating them as if the excess demand in real-time had never existed.

Figure 2: SPD cannot solve during a supply shortfall unless all demand has a price assigned



Source: Electricity Authority

Notes: Generation supply offers are stacked in price order (red). Total demand is a vertical line at the MW quantity (blue); for simplicity, no dispatchable demand bids are shown.

Left panel: SPD cannot solve during a supply shortfall (hatched area), as the demand and supply curves do not intersect

Right panel: assigning a dummy price to demand ($500,000/MWh) allows SPD to solve.

5 GXPs where the system operator can forecast load are termed 'conforming'. Purchasers at non-conforming GXPs are required to submit 'nominated non-dispatch' bids to indicate their consumption. The price information in these bids is only used to calculate the forward price-responsive schedule, but is discarded for dispatch (see paragraph 4.149 for detail). Purchasers at any GXP can apply to participate as dispatchable demand.

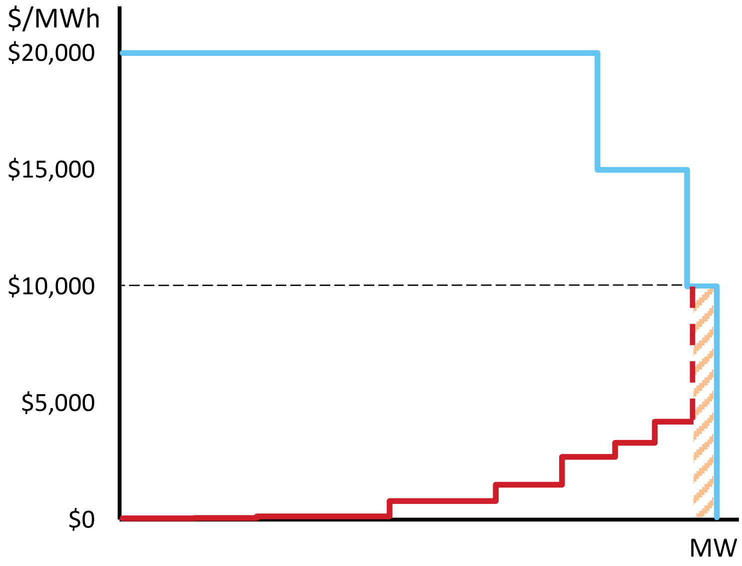
6 The shortfall must occur with no binding constraints on the transmission grid. To date this has never occurred.

Scarcity pricing solves the mathematical problem to deliver RTP

3.5 Other electricity spot markets around the world avoid this mathematical problem simply because they use hard price caps. In these markets, the cap sets the spot price directly during any supply shortfall. By definition, spot prices can never exceed these caps.

3.6 Scarcity pricing performs this role under RTP — not by capping spot prices, but by assigning a real price to expected demand **by default**.[7] These scarcity pricing values are carefully set to account for the estimated cost of investing in new generation supply, and the cost of load shedding. During a supply shortfall, the relevant default scarcity pricing block sets the spot price, as shown in Figure 3. The resulting spot price is real, and will be used for settlement. Under RTP, load shedding may occur despite generation being available to supply total demand: generation offered above the relevant default scarcity pricing block would not be scheduled (as detailed in our 2017 paper).

Figure 3: Default scarcity pricing determines the spot price during physical supply shortfalls under RTP



Source: Electricity Authority

Notes: The three default scarcity pricing blocks are shown using the currently proposed values: the first 5% of demand at $10,000/MWh, the next 15% at $15,000/MWh, the final 80% at $20,000/MWh.

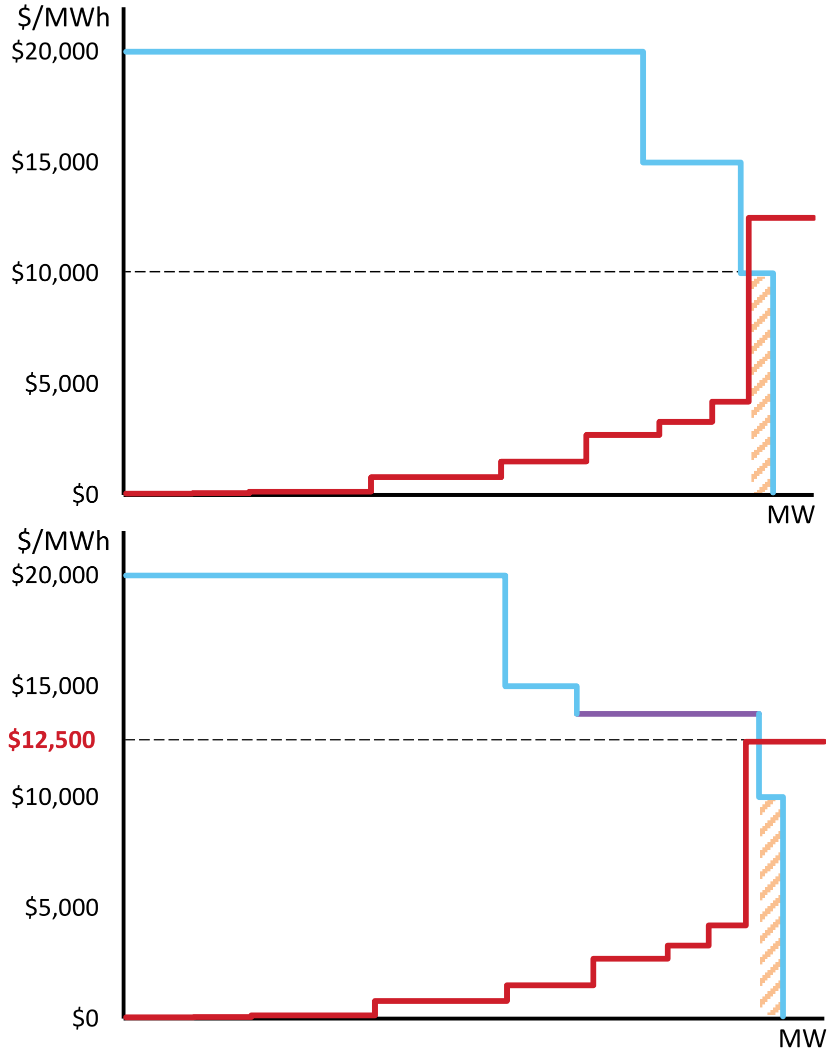
The first 5% block binds during a shortfall in offered generation, determining the spot price.

3.7 Default scarcity pricing is not a price cap, and the values do not represent the Authority's view of acceptable maximum spot prices. The critical distinction is that spot prices can rise above these default scarcity prices if purchasers commit to paying more. This means purchasers reveal their willingness to pay for electricity, replacing the default scarcity prices with price information they provide explicitly.

7 Default scarcity pricing will be assigned to demand forecast by the system operator and to non-dispatchable bids at non-conforming GXPs (see paragraph 4.28 for full details).

3.8 To do so, purchasers must adopt dispatchable demand, or the new dispatchable demand-‘lite’ scheme we are introducing as part of RTP (see section 5). Spot prices can then rise to schedule generation offered above the relevant default scarcity price if dispatchable demand bids exist at or above that offer price. This is illustrated in highly simplified form in Figure 4.

Figure 4: Spot prices under RTP can exceed default scarcity pricing if purchasers commit to paying for higher-priced generation



Source: Electricity Authority

Notes: **Top panel:** the 5% block binds as generation offered below $10,000/MWh cannot supply total demand; the system operator will instruct load shedding (hatched area) for the shortfall. A generation offer at $12,500/MWh is not scheduled (final tranche does not intersect demand).

Bottom panel: a purchaser bids dispatchable demand (purple tranche) priced at $13,750/MWh; the default scarcity pricing blocks adjust to maintain the correct proportions of total demand. The quantity of load shedding at the 5% block is reduced accordingly. The generator is now scheduled to ensure the full dispatchable demand quantity is supplied, setting the spot price.

3.9 We recognise this is an important shift from practice today, where all offered generation will be used to supply expected demand, regardless of the cost. But this design is necessary to meet the inherent and unavoidable mathematical challenge described above. We consider these market outcomes are an acceptable trade-off in delivering the significant benefits RTP will bring. Further:

(a) The scarcity pricing values are carefully considered. They account for factors such as the estimated investment cost for new last-resort suppliers, and the cost of load shedding for different classes of consumers. We also commit to consulting on a review of these values before RTP goes live.

(b) Higher-cost resources can be scheduled if purchasers commit to paying for them, as described above.

(c) In practice, offer prices approaching the current proposed lowest scarcity pricing value of $10,000/MWh are exceedingly rare. From the start of 2015, no ‘real’ offer exceeded $9,000/MWh;[8] the highest offer over that period is for one single generating unit at $8,001/MWh for 20 trading periods on a single day in July 2017.

3.10 Finally, we note any attempt to moderate price outcomes by intervening after the fact compromises the price certainty RTP is intended to provide. It would again violate Principle 1, even if satisfying Principle 2: participants and consumers could not be confident the prices they see in real-time won’t be changed later. This undermines security of supply in turn — potential investors in new generation or demand response resources need to be confident prices signalling capacity scarcity won’t be overridden.

4 The design elements implementing real-time pricing

4.1 The sections to follow set out the design we will adopt to implement RTP. They combine design elements proposed in both our 2017 and 2019 RTP consultation papers. To aid the reader, each section:

(a) begins by referencing the location of relevant material in the paper(s) and any related consultation question(s), and indicates whether the design was ‘upheld’ largely as proposed or ‘revised’

(b) states how the design element will be implemented

(c) where relevant, explains how the design was revised from the original proposed

(d) gives the Authority’s response to relevant matters raised in submissions (submitting parties are cited using the relevant year, 2017 or 2019).

4.2 The sections below assume some knowledge of important concepts for dispatch and pricing. These include how SPD ‘co-optimises’ energy and instantaneous reserve (or simply, **reserve**), and the role of reserve shortfalls. Appendix B provides background on these concepts, reproduced from our 2019 paper.

The design must be robust to all possible circumstances, even if they occur very rarely

4.3 Part of the challenge for designing RTP is handling what are known as ‘edge cases’: circumstances that are likely to happen only very rarely, but cause significant impacts if

8 Offers from one generator for 7 trading periods in August 2018 were priced at $49,500/MWh. We also noted in our 2017 paper that a single tranche was offered at $50,050/MWh for a single trading period in 2016. We consider these prices are most likely input errors.

the system is not designed to deal with them. Today, many of these circumstances require extensive manual intervention as part of the ex-post pricing process (eg, as ‘provisional pricing situations’).

4.4 Some of the design elements detailed below should be viewed in this context. We expect the relevant circumstances to occur very rarely, but we have designed RTP to handle them robustly. Key examples include:

(a) instructing load shedding because the default scarcity pricing blocks are binding

(b) high-spring washer pricing situations

(c) losing high-quality real-time metering for the dispatch process (see paragraph 4.138)

(d) manual claims of a pricing error.

Spot prices will be derived from the system operator’s dispatch schedule

2017 paper paragraph(s):	3.2 – 3.7	on page(s): 12 – 13	and question: 1

UPHELD as proposed

4.5 Spot prices for energy and reserve will be derived from the system operator’s real-time dispatch schedule (RTD). The prices used to settle the spot market will therefore be set by the actions the system operator takes to run the power system in real-time.

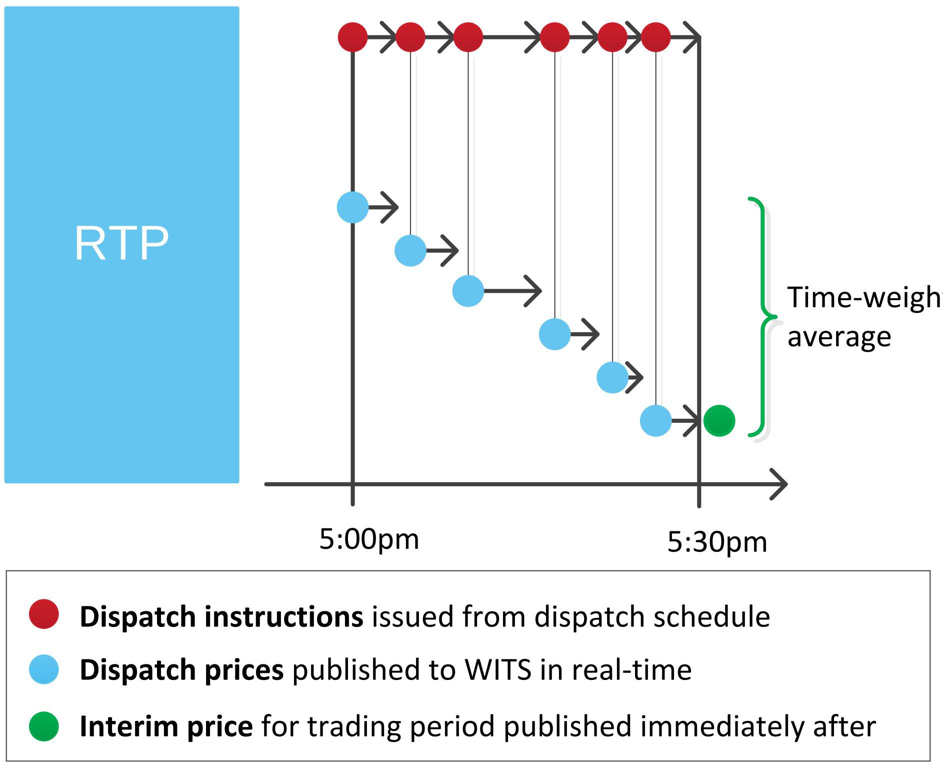
4.6 The system operator automatically calculates a new RTD every five minutes; it may also manually trigger SPD to calculate a new dispatch schedule if required. The system operator has discretion under the Code to decide whether to issue new dispatch instructions from any dispatch schedule. Dispatch instructions are therefore not issued on fixed time intervals in any given trading period.

4.7 New **dispatch prices** and **dispatch reserve prices** will be struck whenever the system operator issues new dispatch instructions from a dispatch schedule, as shown in Figure 5. There will be at least one set of dispatch prices (for every node) and dispatch reserve prices (for each reserve class in each island) for each trading period during normal market system operation.[9] For simplicity, this paper will hereafter use the term ‘dispatch price’ to refer to prices for both energy and reserve, unless specifically discussing prices for reserve.

4.8 New dispatch prices will be immediately published on WITS. Dispatch prices will be ‘good until replaced’ by new dispatch prices (when the system operator issues new dispatch instructions). Typically this will be about every five minutes. Only those dispatch prices available on WITS in real-time during a trading period will be used for final pricing — to be actionable, prices must be visible. Dispatch prices that, for example, are received by WITS out of order or after the end of the trading period they applied to will be discarded.

9 Prices during any market system outages will be determined through the process set out in paragraph 4.199.

Figure 5: Calculating interim prices from dispatch prices in each trading period



Source: Electricity Authority

Notes: Dispatch instructions and hence dispatch prices are shown at varying time intervals within the 30-minute trading period. Dispatch prices visible on WITS are good until replaced. The interim price for a trading period will be calculated and then published on WITS immediately afterward.

Our response to submitter's views

4.9 All 14 submitters responding to this question in our 2017 paper agreed spot prices should be determined by the system operator's dispatch process. ENA (2017), NZS (2017), and Powerco (2017) also broadly supported the proposal in a general form.

4.10 WPI (2017) stated price information needs to be easily accessible on WITS in real-time. We strongly agree. As well as displaying dispatch and interim prices on the WITS web pages, we will ensure it is available from a WITS web services application programming interface (API) in real-time. We expect that web services API to be in place before RTP goes live.

4.11 Orion (2017) agreed with the broad principle of using dispatch prices, but commented:

> If the nub of the problem is actually that forecast prices are an unreliable indicator of final prices, then producing final prices more quickly simply brings forward the disappointment.

4.12 The central conceptual change of RTP is to determine the final prices used to settle the trading period from dispatch prices that are struck and become visible in real-time. Dispatch prices are not *forecast* prices. The core difference is participants and consumers can now act on prices that are *real*, not merely indicators or forecasts of what the real price might turn out to be. We discuss forecast prices in the two forward schedules further in Box 1 and paragraph 4.205.

4.13 We address other matters raised by some submitters in their response to question 1 of our 2017 paper in section 10.

The interim price for a trading period will be the time-weighted average of dispatch prices

2017 paper paragraph(s):	3.8 – 3.12	on page(s): 13 – 17	and question: 2
UPHELD as proposed			

4.14 The interim price for a trading period will be the time-weighted average of the set of dispatch prices visible on WITS during that period (similarly for interim reserve prices). As noted in paragraph 4.8, any dispatch price produced by the system operator but not visible on WITS will be discarded when calculating interim prices.[10] The methodology for calculating interim prices and interim reserve prices is set out in clause 13.134A of the Code amendment.

4.15 Interim prices and interim reserve prices will be calculated by the clearing manager (see paragraph 4.25(a)) and published on WITS immediately after the trading period ends. We expect this will occur within seconds. The overall process is illustrated in Figure 5.

Our response to submitters' views

4.16 Eleven of 12 submitters responding to this question in our 2017 paper supported time-weighted averaging as the pragmatic option to implement RTP.

4.17 Only EnerNOC (2017) disagreed, arguing for volume-weighting as time-weighting would 'dilute' price signals and fail to achieve the full efficiency benefits possible. MEUG (2017) also submitted volume-weighting may be better, though accepted time-weighting is the most practical option.

4.18 While we recognise volume-weighted prices can have efficiency advantages *at individual nodes*, we consider these are substantially outweighed by their flow-on effects. In particular, prices at reference nodes would become problematic for risk management contracts such as futures, contracts for difference, and financial transmission rights. Today — and with time-weighting under RTP — prices at these nodes generally represent prices at other nodes in the surrounding electrical region. But under volume-weighting, different load and generation profiles between reference and surrounding nodes could result in substantial price differences in otherwise similar conditions. We consider the additional time, complexity, and likely cost required to mitigate these drawbacks is not warranted.

4.19 EnerNOC (2017) also proposed RTP should use volume-weighting for instantaneous reserve prices, even if using time-weighing for energy prices. EnerNOC (2017) argued this option would be viable as reserve prices would not be affected by the same restrictions noted above (as they are island-wide).

4.20 We consider forming final prices for energy and reserve differently would increase complexity. In general, volume-weighting strengthens the incentive to respond to individual dispatch prices (and dispatch reserve prices) within a trading period. Volume-

10 We revised clause 13.134A to account for NZX (2017)'s concern that dispatch prices *for* a trading period might be received by the WITS manager *after* that period ended; eg, due to a communications failure.

weighting reserve dispatch prices may then introduce perverse and inefficient incentives for parties offering both energy and reserve.[11] We do not favour this option.

4.21 EnerNOC (2017), Genesis (2017), MEUG (2017), and Trustpower (2017) also submitted there may be merit in a future move to settling on dispatch prices directly. The Australian National Electricity Market (NEM) is due to move to this ‘5/5 settlement’ model in 2021, named for aligning settlement with the 5-minute dispatch intervals.[12] Settling on dispatch prices removes the need for any form of averaging, because interim settlement prices would be known immediately in real-time.

4.22 We consider attempting to settle on dispatch prices directly as part of RTP would incur significant extra costs and likely delay implementation by a number of years. We also consider moving to 5/5 settlement would not bring the same efficiency benefits expected in Australia. This is because New Zealand has significant differences to the NEM:

(a) Unlike the NEM, bids and offers are subject to the gate closure period. This reduces the potential for last-minute revisions resulting in significant and unexpected changes in dispatch prices.

(b) We do not have fixed 5-minute dispatch intervals, as noted in paragraph 4.6. Financial contracts would therefore require substantial changes to reflect the now-uncertain number and duration of settlement prices. These changes would take time and cost to develop.

(c) Unlike the NEM, generators receive constrained on payments and dispatchable demand purchasers receive constrained on and off payments. These payments compensate dispatched participants for differences between final prices and dispatch outcomes inside each 30-minute trading period (ie, make them whole). Participants are then comparatively much less likely to regret being dispatched when final prices depart substantially from individual dispatch prices.

4.23 In summary, we consider time-weighted averaging for both energy and reserve gives the right balance between realising important efficiency gains and the time, cost, and complexity to implement RTP. RTP is a major change to the wholesale market — adding more complicated design choices like volume-weighting or 5/5 settlement at this time carries large risks of delay and unintended consequences.

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11 To understand how these perverse incentives might arise, consider a trading period where the energy and reserve dispatch prices were both $5,000/MWh in the first 5 minutes, then $50/MWh for the remainder. If reserve were settled using volume-weighting and energy using time-weighting, the optimal dispatch for a 10 MW generator providing both would be 100% reserve in the first 5 minutes, then 100% energy in the remaining 25 minutes. The generator maximises revenue by switching, receiving about $8,000. If instead the generator were dispatched at 5 MW of reserve and 5 MW of energy, it would receive about $4,400. This difference is not sensible or efficient. Dispatch prices for reserve and energy were the same throughout the trading period, so each is equally scarce — the generator should be equally rewarded when providing either.

12 The NEM is currently settled on 30-minute averages of strictly 5-minute dispatch prices, or 5/30 settlement. For details see the Australian Energy Markets Commission *Five Minute Settlement* Rule change at https://www.aemc.gov.au/rule-changes/five-minute-settlement.

The clearing manager will calculate interim prices and be responsible for making them final

2017 paper paragraph(s): 3.13	on page(s): 17 – 18	and question: 3
UPHELD as proposed		

4.24 The pricing manager will be disestablished, as its principal function to calculate the current ex-post final pricing schedule will cease under RTP.

4.25 The clearing manager will be assigned the residual pricing roles:

(a) automatically calculating interim prices and interim reserve prices as described from paragraph 4.14, and automatically publishing those prices on WITS immediately after the relevant trading period ends

(b) changing the status of prices from interim to final:

(i) automatically at 14:00 on the first business day after the trading day if there is no claim of a pricing error (under clause 13.182A)

(ii) one hour after the Authority determines no pricing error has occurred or rejects a pricing error claim (under clause 13.182B)

(c) recalculating and publishing replacement interim prices if a pricing error claim is upheld (under clause 13.177), as detailed from paragraph 4.183.[13]

Our response to submitters' views

4.26 All 11 submitters responding to this question in our 2017 paper agreed with our proposal to assign the residual roles to the clearing manager.

4.27 Orion (2017, 2019) stated it was unclear when *final* prices are to be produced, how long before real-time they will be known, and how long a set of real-time prices persist. In combination, the three design elements above answer these questions:

(a) Dispatch prices will be produced whenever the system operator issues dispatch instructions. This will occur at least once for each trading period, and commonly about every 5 minutes. Dispatch prices become known in real-time — they reflect a change in system conditions causing the system operator to re-dispatch. Dispatch prices apply until replaced within a trading period.

(b) Interim prices will be calculated and published on WITS immediately after a trading period ends. As noted above, this should be on the order of seconds.

(c) These interim prices become final prices at 14:00 the next business day after that trading period, unless a pricing error is claimed.

[13] Recalculating interim prices if a pricing error claim is upheld in effect 'resets' the timer for those interim prices to then become final.

All demand not the subject of a bid will be assigned to default scarcity pricing blocks

2017 paper paragraph(s): 3.14 – 3.22 on page(s): 18 – 21 and question: 4

UPHELD as proposed

4.28 The system operator will automatically assign scarcity prices to all demand that is not the subject of a bid. The demand quantities at each GXP will be assigned proportionally across three **default scarcity pricing blocks**, configured as shown in Table 2 and illustrated in Figure 6. The system operator will instruct emergency load shedding if the demand assigned to default scarcity pricing blocks cannot be fully supplied in real-time (see details from paragraph 4.45).

4.29 As explained in our 2017 paper (page 19 and Appendix D), the size of each block reflects a range of factors:

(a) The cost of load shedding should rise in line with the quantity.

(b) A modest proportion of demand at each GXP — the first 5% — should have the lowest scarcity price. This is likely enough to address many shortfall situations, given 5% of load summed across multiple GXPs can be a significant total quantity. The intermediate block (15%) is assigned a higher price reflecting the greater severity of curtailment.

(c) The small size of the first block also means any load shedding is likely to be shared across multiple GXPs. In contrast, a single scarcity pricing block would concentrate load shedding at individual (or a few) nodes simply because of differences in transmission losses.

(d) The total of the first (5%) and second (15%) block approximates the 'comfortable' maximum level of demand management at most distribution networks. Together, this 20% of load should be enough to deal with most emergency situations.

(e) Demand at the final (80%) block is assigned the highest scarcity price, as load shedding at this depth would almost certainly reflect extreme conditions.

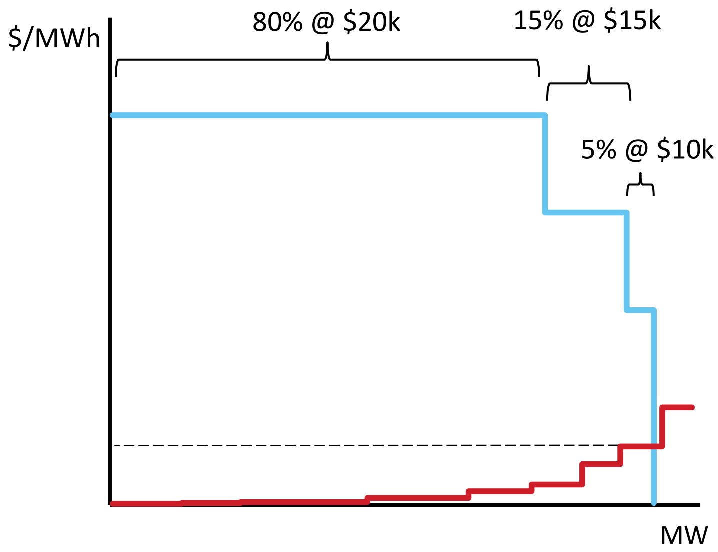
4.30 The dollar values are based on the current scarcity pricing provisions in the Code. These values are also set directly in the Code in the amendment attached as Appendix A. However, we will consider whether they should be specified in a separate instrument during RTP's build phase, as discussed from paragraph 10.2.

4.31 The default scarcity pricing blocks will be fully configurable in SPD. The number of blocks, proportion of load, and prices can all be changed if and when required in future.

Table 2: Default scarcity pricing blocks under RTP

Proportion of load	Assigned price
First 5%	$10,000/MWh
Next 15%	$15,000/MWh
Last 80%	$20,000/MWh

Figure 6: RTP builds a closed demand curve by assigning default scarcity prices to all load not bid as dispatchable



Source: Electricity Authority

4.32 In dispatch schedules, default scarcity pricing will be applied to all load not bid as dispatchable demand (or dispatch-'lite'). For the two forward schedules producing *forecast* prices before real-time:

(a) load in the non-response schedule (NRS) is treated the same as in the dispatch schedule

(b) load in the price-responsive schedule (PRS) also uses the prices specified in non-dispatch bids as well as dispatch bids.

4.33 This information is shown graphically in Table 3; full details for all bid types are set out in Appendix C. For clarity, the source information for the expected load quantities also differs between the forward schedules and dispatch. Box 1 explains this difference.

Table 3: Prices used for load quantities by schedule type

	Forward schedules		Dispatch
	PRS	NRS	RTD
Forecast load at conforming GXPs	Scarcity pricing blocks	Scarcity pricing blocks	Scarcity pricing blocks
Non-dispatch bids at any GXP	Bid price	Scarcity pricing blocks	Scarcity pricing blocks
Dispatch bids at any GXP	Bid price	Bid price	Bid price

Source: Electricity Authority

Notes: PRS = price-responsive schedule, NRS = non-response schedule, RTD = real-time dispatch schedule (used to produce dispatch prices under RTP)

Box 1: Load forecasts used in dispatch are separate from the load forecasts used in the forward schedules

Comments across submissions indicated a degree of confusion about the system operator's load forecasts and how they are used in dispatch and the forward schedules. To clarify, the system operator maintains two distinct load forecasts for these different schedules:

- **Short-term load forecast** (STLF): the STLF is used in the dispatch process, as a demand input to the dispatch schedule. This is the forecast of load at conforming GXPs. It projects into the next roughly 5 minutes for dispatch, indicating how that load is expected to change. The STLF process will be improved as part of implementing RTP, as discussed from paragraph 4.137. The STLF defines the expected load at conforming GXPs for dispatch; load at non-conforming GXPs will move to using a persistence forecast, as discussed from paragraph 4.146.
- **Medium-term load forecast** (MTLF): the MTLF is calculated separately using a different software tool. This is the forecast profile of load at conforming GXPs over the coming 72 hours to calculate PRS and the NRS. Load at non-conforming GXPs will continue to be determined by non-dispatch bids (as shown in Table 5). The MTLF process is not being modified as part of implementing RTP, as discussed in paragraph 10.8.

Our response to submitters' views

4.34 Ten of 12 submitters responding to this question in our 2017 paper supported using default scarcity pricing blocks as proposed.

4.35 Contact (2017) and MEUG (2017) were concerned the dollar amounts in Table 2 may not be appropriate by the time RTP goes live, as they have not been reviewed since 2011. Genesis (2017) was also concerned there was no specific process for reviewing these values.

4.36 We agree these dollar amounts should be reassessed. We will review them before RTP goes live in 2022, and as part of the Authority's periodic review of scarcity pricing values (see sections 6 and 8).

4.37 IEGA (2017) agreed with our proposal, but queried how the system operator accounts for embedded generation (connected to distribution networks) in forecasting demand.

4.38 The expected demand calculated for each GXP is always net of any generation not offered into dispatch. The system operator's dispatch process only 'knows' about resources that are bid or offered. Any embedded generation at a given GXP not offered into dispatch simply changes the net demand for that GXP that SPD seeks to supply. It plays no direct role in price formation, though the now-reduced net demand may lower the spot price. If embedded generation chooses to offer under RTP — such as by taking up dispatch-lite — the demand forecast will account for its injection and avoid 'double-counting'. In all cases, any embedded generator receives the final spot price at that GXP for its metered output.

4.39 Trustpower (2017) submitted it was uncertain about assigning scarcity pricing values to load. It suggested an alternative approach using a 'proxy generator', arguing this avoided potential confusion around SPD having to 'remember' how much load was shed.

4.40 We have designed RTP in close cooperation with the system operator. We consider assigning scarcity pricing values to load is the appropriate design for implementing RTP:

(a) it 'closes' the demand curve (as shown in Figure 6), so all demand inputs now have a price, allowing SPD to trade these off to minimise total cost

(b) logically, it best represents the physical conditions, as forecast demand will not be fully supplied.

4.41 We do not consider a proxy generator would be superior. The system operator's detailed technical design will incorporate the need for SPD to remember the quantity of load shed in a previous dispatch schedule. In fact, this would effectively also be required in using a proxy generator — the load quantity that generator must supply is the quantity shed. We do not consider this would reduce possible confusion about emergency load shedding. In fact, it would add complexity by requiring load forecasts to now also include the varying proxy generator quantity (GXP meters can't record load that doesn't exist).[14]

4.42 Orion (2017) disagreed with using scarcity pricing as proposed, arguing that, if the default scarcity pricing blocks are used:

(a) the values 'should at least reflect the actual resources available to the system, many of which are usually available at much lower cost than the values proposed' (Orion (2019) repeated this view.)

(b) more attention is needed on the potential for generators to withdraw offered capacity when pivotal to induce scarcity prices; and that the safe harbour provisions in the Code should be reviewed accordingly.

4.43 The system operator can only dispatch the resources actually made available to it through bids and offers. Other resources may exist — and may respond to dispatch prices during scarcity — but have not been made available for dispatch, by definition. If those resources are lower cost, the potential for scarcity prices under RTP gives an

[14] A proxy generator may have been a workable option if RTP continued to derive forecast load from current dispatched generation, the same as today (see the discussion from paragraph 4.137).

incentive to participate in dispatch by bidding or offering at lower prices. That participation could be direct, or by other parties such as retailers contracting with the owner of those resources. Doing so would reveal more information about the costs of supply and consumers' willingness to pay, making resulting spot prices more efficient. We expect RTP will help encourage these more efficient prices over time.

4.44 Regarding Orion's (2017), second point: we will ensure the trading conduct provisions in the Code are robust to the new dispatch and pricing arrangements introduced by RTP (see section 7). We will also ensure our compliance processes monitor generator behaviour in such circumstances once RTP goes live.

The system operator will instruct emergency load shedding if the default scarcity pricing blocks are not fully scheduled

2017 paper paragraph(s):	3.23 – 3.28	on page(s): 21 – 22	and question: 5

UPHELD as proposed

4.45 An **unsupplied demand situation** will occur under RTP if demand assigned to a default scarcity pricing block is not scheduled to be fully supplied. The relevant default scarcity pricing block would be binding in a schedule, and would hence set the price. If the system operator issues instructions from that schedule, the default scarcity pricing block then sets dispatch prices. The system operator will instruct emergency load shedding for the resulting energy shortfall — the quantity not supplied.

4.46 As detailed in section 3, load shedding may occur under RTP despite available generation being offered at prices above the relevant default scarcity pricing block.

4.47 Unsupplied demand situations will be grounds for issuing warning and grid emergency formal notices under clause 5 of Technical Code B of Schedule 8.3 of the Code. Clause 6 of Technical Code B in turn provides for the system operator to instruct emergency load shedding for unsupplied demand situations during a grid emergency. Operationally, this means scarcity pricing may be visible to participants and consumers ahead of real-time if a default scarcity pricing block is binding in a forward schedule. If this unsupplied demand situation occurs:

(a) *outside* gate closure, the system operator will issue a warning notice, requesting more supply resources be made available through bids and offers

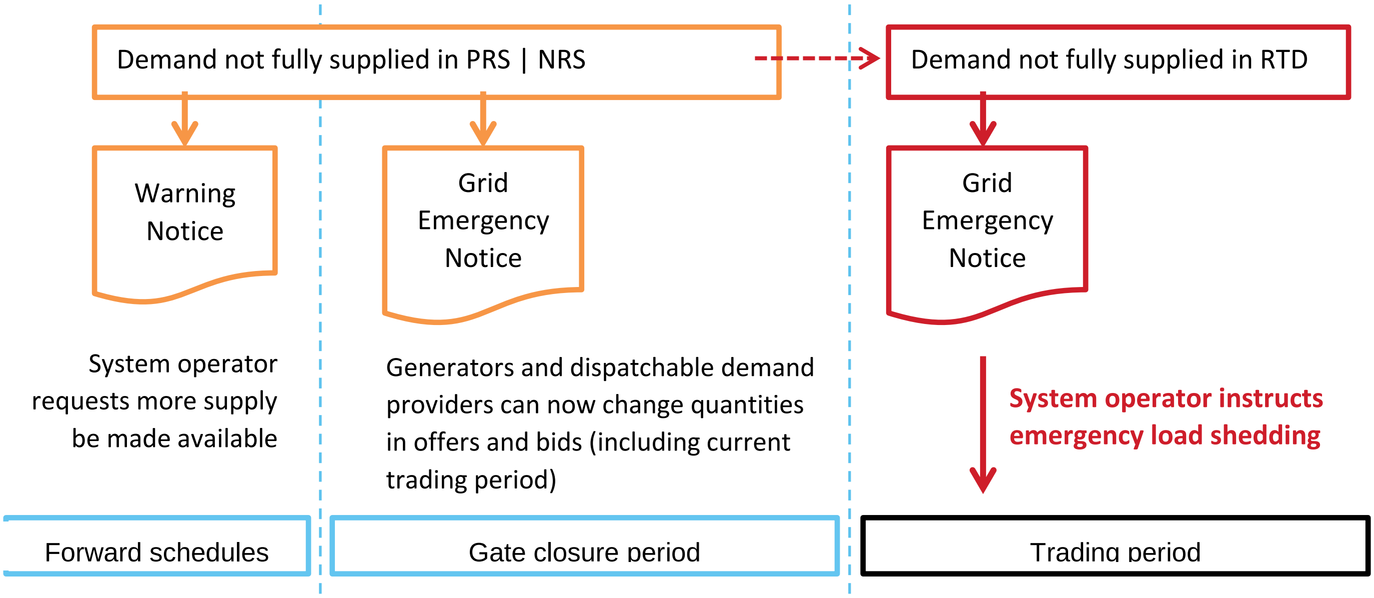
(b) *inside* gate closure, the system operator will issue a grid emergency notice (GEN), thereby allowing participants to rebid or reoffer to increase supply, including during the current trading period

(c) in a dispatch schedule, the system operator will instruct emergency load shedding, for the MW quantity that cannot be supplied at the relevant GXP(s).

4.48 Participants and consumers can therefore see and react to unsupplied dispatch situations ahead of time, if they occur in forecast conditions in the forward schedules. That reaction, either to a warning notice (outside gate closure) or GEN (inside gate closure), may be sufficient to avoid the shortfall and hence avoid scarcity pricing. Reacting to dispatch prices once load shedding is in effect may also alleviate the shortfall in real-time, meaning scarcity pricing only applies for part of the trading period.

4.49 Figure 7 illustrates the potential sequence of warning and grid emergency notices up to an instance of load shedding in real-time.

Figure 7: Unsupplied demand situations may be visible ahead of real-time



Source: Electricity Authority

Notes: **Possible events up to and during real-time (left to right):** Unsupplied demand situations *may* be visible in the forward schedules ahead of real-time, but this is not guaranteed. Emergency load shedding will be instructed if the default scarcity pricing blocks are binding in an RTD schedule.

Our response to submitters' views

4.50 Eight of 10 submitters responding to this question in our 2017 paper supported load shedding during unsupplied demand situations as proposed.

4.51 While they agreed, Contact (2017), EnerNOC (2017), IEGA (2017), and Trustpower (2017) raised concern the dollar values to be used may be too low to encourage efficient investment (similar to the concerns noted in paragraph 4.35). Contact (2017) in particular stated the scarcity pricing values will act as a price cap.

4.52 We strongly agree scarcity pricing plays a vital role in supporting efficient investment. We will review the dollar amounts before RTP goes live in 2022, and as part of the Authority's periodic review of scarcity pricing values (see sections 6 and 8). The methodology to calculate these values — set out in Appendix F of our 2019 paper — accounts for the expected investment cost of last-resort generation as a key factor.

4.53 Importantly, default scarcity pricing blocks are not a price cap because they can be exceeded, as explained in section 3. Further, at 5% only a modest quantity of load is assigned to the first default scarcity pricing block at (currently) $10,000/MWh. Higher-priced generation is then likely to be used during any period of significant physical capacity shortfall.

4.54 On balance, we consider RTP will provide clear and appropriate price signals to encourage investment in last-resort resources — where efficient to do so, given the markedly increased potential for demand response RTP will provide.

4.55 Orion (2017) only ‘partially’ agreed, citing the reasons we addressed in paragraph 4.43.

4.56 IEGA (2017) did not agree, raising concern that embedded generation will not be ‘allocated to the supply side’. It submitted scarcity pricing acts as a price cap for embedded generators as price takers at a GXP, undermining price signals for investment.

4.57 We consider IEGA’s concerns are broadly addressed by adopting its suggestion to expand dispatch-lite to include distributed generation (see section 5). We also note:

(a) Embedded generation is on ‘the supply side’ when it elects to offer into dispatch. If not, embedded generation is unknown to the system operator and can only be part of net load for the GXP, as discussed in paragraph 4.38. We consider dispatch-lite will make it easier for embedded generators to be dispatched and hence participate in price setting under RTP. Doing so would address the existing potential for embedded generation to reduce spot prices by reducing net load.

(b) Our position on scarcity pricing acting as a price cap is set out above and in section 3. This applies equally to embedded generation.

(c) Embedded generators receive the final price at the GXP for their metered output. That final price will be set by default scarcity pricing in the event of a supply shortfall. If embedded generators remain price takers, they will therefore benefit from scarcity pricing under RTP. In contrast, any localised load shedding instead suppresses spot prices under current arrangements. Instances of scarcity pricing at a GXP will be a clear signal that more distributed generation would be valuable.

The system operator will instruct emergency load shedding the same way it does today

2017 paper paragraph(s):	3.29 – 3.36	on page(s): 22 – 23	and question: 6
UPHELD as proposed			

4.58 We will not change the rights and responsibilities of the system operator or distributors for carrying out emergency load shedding under the Code. We will not introduce a facility to electronically communicate with distributors for this purpose as part of RTP. The system operator retains its existing discretion in responding to real-time energy shortfalls under Technical Code B of Schedule 8.3. This allows a degree of pragmatism when instructing distributors to manage load at individual GXPs. Any exercise of discretion will be recorded and can be scrutinised afterward.

4.59 It is possible scarcity prices could apply in a dispatch schedule, but the system operator’s real-time monitoring tools indicate load shedding is not needed. The reverse could also happen, where the system operator instructs load shedding but scarcity pricing does not apply. Were either to occur, we expect the system operator will quickly update its model to match system conditions. Dispatch prices from the subsequent dispatch schedules would then reflect the system operator’s actions.

Our response to submitters’ views

4.60 Eleven of 13 submitters responding to this question in our 2017 paper agreed the existing processes to notify distributors of load shedding are sufficient for RTP. Powerco

(2017) also stated the existing processes are acceptable. Vector (2017) stated retaining discretion for handling emergency load shedding under RTP is 'pivotal'. Contact (2017) suggested any changes should come separately to RTP, and should leverage the system operator's capabilities being introduced by its Dispatch Service Enhancement project (DSE).[15]

4.61 However, Mercury (2017) disagreed, stating load shedding processes need to be well-documented, transparent, efficient, use modern technology, and be published publicly. Trustpower (2017) also noted greater transparency of load shedding would be valuable.

4.62 We agree these processes need to be well-documented and published publicly. The system operator will document and publish its processes as part of implementing RTP. As well as being visible in dispatch schedules — though this is not guaranteed, as noted above — instances of emergency load shedding will be recorded and made public. We consider the system operator's DSE project may separately lead to improved communication with distributors by the time RTP goes live. For example, distributors may wish to adopt new communication technologies for other purposes (such as for providing interruptible load in the instantaneous reserve market). But we will not require those changes for RTP.

4.63 IEGA (2017) did not state a position, but again queried how distributed generation could participate in this context. We addressed this by expanding dispatch-lite, as set out in section 5.

4.64 Orion (2017, 2019) commented in detail on its concerns around processes for distributors to shed load in real-time. Powerco (2017) also briefly noted some of these concerns. Orion raised matters including:

(a) How will the system operator remember the quantity of load shedding for the next dispatch schedule? What happens when scarcity pricing causes demand response that reduces load back below that scarcity level (ie, it can again be fully supplied)?

(b) The actions of distributors may interact with dispatched resources (eg, if connected to the same network feeder). As a result, there could be overshoot or undershoot in the target maximum net load at the GXP.

(c) The volume of load control available to distributors varies and can be 'lumpy', so may not readily match the required quantity to be shed. Distributors like Orion also switch loads between GXPs in its network, so neither the system operator nor the participant can know for sure where loads are connected in real-time. How will the system operator account for this?

(d) Distributors such as Orion manage load to a target limit in its network region. This means other forms of demand response can be negated — Orion would restore the load it controls to raise total load back to the regional limit.

4.65 We recognise these operational complexities, and accept Orion's (2019) position that distributors 'have their own constraints and operational imperatives'. The Authority and the system operator agree with Orion that we should develop detail around these

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15 The system operator's DSE project is replacing the existing GENCO dispatch system with modern communications protocols, using either ICCP or web services. DSE is expected to go live in August 2019. Our 2017 paper referred to DSE by its former name, EDF Phase III. Further information on DSE is available at https://www.transpower.co.nz/system-operator/so-projects/dispatch-service-enhancement-project and https://www.ea.govt.nz/development/work-programme/operational-efficiencies/dispatch-service-enhancement/.

processes during RTP's build phase, covering a range of operational scenarios. We will engage further with distributors and participants for this purpose. The system operator and the Authority welcome Orion's offer to collaborate in this work.

4.66 We also make the following points in response to the matters Orion raised:

(a) Dispatch schedules will specify the MW quantity of load to be reduced in any unsupplied demand situation. The system operator will then instruct distributors to control load to a maximum MW level at relevant GXP(s). These instructions use the existing provisions under clause 7A of Technical Code B in Schedule 8.3 of the Code. The maximum level will be the MW quantity that can be supplied, accounting for the energy shortfall. Distributors have significant discretion about how they meet this obligation; we expect tools like ripple control of hot water would be used first. We consider discretion available to both the system operator and distributors is sufficient to manage operational factors like lumpier loads.

(b) SPD will remember this shortfall quantity (the MW of load shed) for the next dispatch schedule, as noted in paragraph 4.41. If a shortfall remains, instructed load shedding and hence scarcity pricing will persist. But if demand responds to those scarcity prices and net load at the GXP falls below the shortfall quantity, prices will return to 'normal' and instructed load shedding will cease.[16]

(c) Distributors switching load between GXPs is a known issue today, and the system operator has processes to account for this — when made aware of it. This issue is not specific to RTP, but the system operator will engage with distributors during RTP's build phase. Orion's suggestion of a 'block dispatch' approach to load management within a distribution region could be developed further.

(d) The potential for distributor actions to affect dispatched resources is also not specific to RTP, and participation in dispatch could increase for other reasons. RTP may lead to participants and potential participants making more specific arrangements with their distributor to account for that risk. Ultimately however, the need to manage load to a maximum limit as directed by the system operator will continue.

(e) More voluntary demand response to scarcity prices in real-time reduces the amount of (forced) load management distributors require to meet the maximum target.

4.67 Scarcity pricing under RTP provides clear incentives for purchasers to engage in demand response. Bidding controllable load sources into the wholesale spot market as dispatchable demand or dispatch-lite allows purchasers to set spot prices based on their willingness to pay. This dispatched demand response can therefore avoid scarcity pricing (on the rare occasions where this might occur). Purchasers may seek to contract distributor load control for this purpose.

4.68 Ultimately, distributed energy and demand response technologies and related business models are evolving rapidly. The Authority is also pursuing a range of related work in the distribution context, with projects spanning: efficient distribution pricing; the default

[16] We provided a worked numerical example illustrating these outcomes in our response to queries from Trustpower during our 2017 RTP consultation period. See the worked example from page 5, available on our website at https://www.ea.govt.nz/dmsdocument/22579-response-to-trustpower-queries-regarding-our-proposal-for-real-time-pricing. That example was for an islanded situation, but the same principles apply in general.

distributor agreement (DDA); additional consumer choice of electricity services (ACCES); and the open networks development programme, responding to the innovation and participation advisory group's (IPAG) advice on equal access. Opportunities and arrangements for demand response are likely to have developed further by the time RTP goes live in late 2022.

The proxy price at disconnected GXPs will be set to the price of the electrically-nearest live GXP

2017 paper paragraph(s):	3.37 – 3.40	on page(s):	24	and question:	7

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4.69 GXPs marked as electrically disconnected in the system operator's modelling system will be assigned a proxy price. Dispatch prices for these nodes will be set to the same price as the electrically-nearest live node. The system operator will determine the full technical details of the process to implement this design during RTP's build phase.

4.70 A proxy price is necessary to account for planned transmission outages, as these do not start or end exactly on trading period boundaries. This means load or generation can be electrically connected for part of a trading period, even though SPD sees the relevant transformer(s) as disconnected from the grid. Without an overriding proxy price, any load electrically connected to that node would then trigger default scarcity prices in the dispatch schedule (as there is no matching supply). That outcome would be spurious, purely the result of a mismatch between the model and actual conditions.

How this changed from our proposal

4.71 In our 2017 paper we proposed setting the proxy price for a disconnected node based on an appropriate reference node, adjusted for the historical location factor. Further technical investigation by the system operator has since identified the electrically-nearest live node can be used for this purpose instead.

4.72 We consider this alternative is superior. Prices would more accurately reflect relevant conditions on the power system in real-time in that electrical area.

Our response to submitters' views

4.73 Eight of 9 submitters responding to this question in our 2017 paper supported using a proxy price for disconnected nodes.

4.74 EnerNOC (2017) disagreed, arguing the proxy price should instead be determined by the 'next most suitable node'. While it agreed with our proposal, Meridian (2017) also argued the historical location factor should be based on a similar grid configuration.

4.75 We consider adopting the system operator's revised suggestion to use price of the electrically-nearest live node addresses both of these points.

There will be no cumulative limit to scarcity pricing

2017 paper paragraph(s):	3.41 – 3.46	on page(s): 24 – 25	and question: 8

UPHELD as proposed

4.76 We will remove the current cumulative limit on applying scarcity pricing in clause 13.135C of the Code.[17] Today, this prevents scarcity pricing from applying if the generation-weighted average price across the previous week (336 trading periods) exceeds $1000/MWh in an island or nationally. Applying such an ex-post scarcity price limit is not consistent with the fundamental principle of actionable prices under RTP: prices should not be subject to uncertain intervention after the fact.

4.77 As noted in our 2017 paper, we expect the system operator would use the current rolling outage provisions in Part 9 of the Code if sustained load shedding is needed. The default energy scarcity pricing blocks are not likely to bind if rolling outages are in use — demand would already have been reduced to meet available supply through external 'out of market' intervention.

Our response to submitters' views

4.78 Eight of 10 submitters responding to this question in our 2017 paper supported removing the limit. EnerNOC (2017) noted retaining an ex-post limit on applying scarcity prices 'will result in distorted price signals being sent to the market'.

4.79 Orion (2017) and Trustpower (2017) submitted a limit should be retained. Orion (2017) noted the limit was introduced to 'ameliorate cumulative financial effects during sustained high priced periods'. It argued this rationale remains valid, so a limit should be retained. Trustpower (2017) argued a limit mitigates price risk to retailers during tight market conditions, and that:

(a) would be consistent with an expectation the value of lost load would fall during scarcity events (eg, consumers switching to gas appliances for cooking during an outage)

(b) aligns with 'the fact' scarcity prices are administered values, would not be used that frequently, and hence a limit would not distort investment signals.

4.80 We agree the value of lost load is not fixed, and varies with the length of outages. However, the default scarcity pricing values already account for this factor, as explained in our 2019 paper (the methodology set out in Appendix F).

4.81 We recognise Orion's point that the current cumulative limit was introduced as a 'stop-loss' mechanism to limit the price risk for retailers and other purchasers. However, the current limit *does not guarantee* prices will be lower or financial effects will be contained. Spot prices during tight market conditions today could still exceed the current $10,000–$20,000/MWh scarcity pricing range: there is no mechanism preventing 'normal' spot prices being set by energy offers priced at or above $10,000/MWh (subject to the good trading conduct provisions; see section 7). In other words, preventing ex-post scarcity pricing from applying in no way ensures prices will be below scarcity values.

[17] The current scarcity pricing arrangements are set out in clause 13.135A –13.135C and Schedule 13.3A of the Code, in the event the pricing manager declares an island or national scarcity pricing situation occurred.

4.82 Further, the existing limit is specific to current ex-post arrangements that apply scarcity pricing at least island-wide. It cannot readily be translated to a real-time pricing model, and doing so would have two serious drawbacks.

4.83 First, attempting to design and apply a cumulative price limit under RTP would require us to determine in advance how widespread scarcity prices must be to trigger intervention. Again, this is because scarcity pricing is nodal under RTP, not applied ex-post to all spot prices in an island. That is, we would need to determine how many nodes must be involved, and where those nodes are located. This threshold would be somewhat arbitrary, and criteria suitable for larger retailers may be poorly suited to smaller retailers.

4.84 Second, the default scarcity pricing blocks can't be 'turned off': they define the demand curve for each GXP, which SPD then uses to determine dispatch (see section 3). Overriding scarcity prices would therefore require defining some replacement administered price and then either: replacing published dispatch prices in real-time; or replacing the interim price for a trading period in real-time, or replacing interim prices later through some other process. Replacing interim prices degrades price certainty (failing design Principle 1 in section 3). Replacing dispatch prices also degrades system security by sending a perversely weak price signal during scarcity conditions. For example, non-dispatched distributed generation may reduce output, or loads may increase consumption, in response to artificially lower real-time prices. All options are counter to the objective of RTP, and erode the vital function of scarcity prices in supporting efficient investment.

4.85 Finally, RTP itself also reduces the need for intervention, because scarcity prices will be visible as they happen through published dispatch prices. This gives a clear signal to consumers and distributed generation that reducing load or increasing supply at affected GXPs is valuable. That response can in turn ameliorate the scarcity conditions, lowering prices in the next dispatch schedule. In contrast, scarcity pricing situations today are only known for certain the next business day, and are not necessarily visible in real-time.

4.86 Transpower (2017) was also concerned the system operator may be pressured to use rolling outages to avoid scarcity prices. We accept Transpower's concern, but consider this risk is minor:

(a) The system operator will direct emergency load shedding based on clear information in dispatch schedules. That information will be much more transparent to participants than it is today. Better information will make it easier for participants and stakeholders to scrutinise both emergency load shedding, and the possible use of rolling outages.

(b) The system operator must consult with the Authority before using rolling outages to avoid emergency load shedding.[18] The Authority would take careful account of conditions in the market in determining whether to support the use of rolling outages. The system operator would therefore have the Authority's public backing in rejecting inappropriate calls to intervene.

18 Rolling outages (as planned outages) can only be used to avoid emergency load shedding (ie, unplanned outages) if a 'supply shortage declaration' is in effect under clause 9.14 of the Code.

Risk-violation curves will enable sacrificing reserve cover to meet demand ahead of emergency load shedding

2017 paper paragraph(s):	3.47 – 3.50	on page(s): 25 – 27	and question: 9
2019 paper paragraph(s):	4.36 – 4.73	on page(s): 30 – 45	and question: 10, 11
UPHELD as proposed			

4.87 We will implement the '**risk-violation curve**' approach to handling shortfalls in reserve under RTP, as proposed in our 2019 paper. That proposal superseded the high-level discussion in our 2017 paper on sacrificing reserve cover before triggering emergency load shedding. Given the technical complexity of the risk-violation model, we outline our decision here in summary form. Full details of the model are set out in section 4 of our 2019 paper, and in further technical material published during the consultation period.[19] Appendix B gives background on how reserve insures against 'contingencies'.

The risk-violation model sets a rising reserve price as reserve shortfall grows

4.88 Under RTP, each source of supply 'risk' will be assigned a new variable in SPD.[20] This 'risk violation' variable represents the MW quantity of that risk not being covered by scheduled reserve. The value of each risk violation variable rises with the size of any reserve shortfall, and simultaneous multiple risks may be not be fully covered. A given MW reserve shortfall may result in different sized risk-violations for particular supply sources, based on their scheduled capacity.[21] This is an important conceptual shift from current practice, which instead only considers the size of the reserve shortfall itself.

4.89 There will be a cost for violating a risk, implemented as a stepped series of price-quantity tranches. Combined, these tranches form a risk-violation curve. Violating the risk for the MW quantity in each tranche will incur a cost set by the corresponding price. Prices for reserve will therefore rise as the quantity of risk not being covered increases during reserve shortfall. This rising cost reflects the economic cost of leaving a growing quantity of risk uncovered — the growing risk of triggering widespread automatic under-frequency load shedding (AUFLS) if a contingent event occurred. Where multiple individual risk sources are not fully covered, reserve prices will increase accordingly.

4.90 SPD will trade-off these risk-violation costs as part of its dynamic co-optimisation process in scheduling resources to supply energy and reserve. By configuring prices in the risk-violation curve below the default scarcity pricing blocks, SPD is therefore able to schedule reserve shortfalls before emergency load shedding. But this is not guaranteed (or physically possible) in all circumstances.

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19 The supporting technical material is available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/technical-material-on-the-risk-violation-curve-design/. See also the video and slides from our public briefing held 29 March 2019, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/events/.

20 Supply risks are the generating units and transmission circuits in operation.

21 For example, suppose scheduled reserve is 200 MW, leaving a 50 MW reserve shortfall. Generator A is scheduled for 210 MW, generator B for 250 MW, and the HVDC for 230 MW. Their respective risk-violations are therefore 10 MW, 50 MW, and 30 MW.

Risk-violation curves produce efficient price signals during reserve scarcity

4.91 Driven by the risk-violation curve, reserve prices during reserve shortfalls will efficiently signal the growing risk to the power system. This meets two important needs:

(a) Operationally, reserve prices will signal scarcity in the forward schedules and in real-time, reflecting the relative value of energy and reserve. Participants and consumers can then react to those prices to allocate resources to their most valuable use, given conditions on the power system.

(b) Efficient prices during reserve scarcity in real-time — ie, in dispatch reserve prices — support investment in adequate resources over the long-term. An increased frequency and duration of high reserve prices signals more investment in resources to provide reserve may be valuable.

4.92 The risk-violation curve is illustrated below in Figure 8. We address the specific configuration of the risk-violation curve in the following sections.

Our response to submitters' views

4.93 All 7 submitters responding to question 11 in our 2019 paper supported adopting the risk-violation model for handling reserve shortfalls under RTP.

4.94 At a higher level, 10 of 11 submitters responding to question 9 in our 2017 paper supported continuing the existing practice of sacrificing reserve before load shedding. While Contact (2017) stated it did not believe this practice should continue, it subsequently agreed we should implement the risk-violation model in its 2019 submission.

4.95 Enel X (2019) stated the risk-violation curve should be configured to ensure reserve shortfall does not occur if offered generation is available, regardless of offer price. But this is not possible, for the same principles set out in section 3 above. SPD cannot apply the risk-violation curve only if some other conditions are met (eg, no offered generation remains). This means SPD will 'choose' to violate risk and hence incur reserve shortfall if that dispatch solution is lowest total cost. In simple terms, SPD will schedule reserve shortfall at the relevant risk-violation cost if this is cheaper than scheduling generation offered at a higher price. This outcome efficiently trades-off the economic costs of the options available to SPD through its co-optimisation process.

4.96 Orion (2019) stated the risk-violation model 'seems reasonable', but queried if this solution is needed only because of the way energy and reserve are co-optimised. Most importantly, because SPD dynamically determines the target reserve quantity for each dispatch schedule.[22] Orion asked whether, if this approach was 'unusual internationally', would removing co-optimisation be superior.

4.97 In response to Orion's (2019) question, we emphasise that co-optimisation is a major advantage of New Zealand's wholesale spot market. Co-optimisation is also established practice internationally; for example, the Australian NEM co-optimises energy and its equivalent of instantaneous reserve (but not risk). In fact, other markets are now moving to implement co-optimisation (eg, ERCOT in Texas).[23] We are unaware of any electricity market deciding to remove co-optimisation. Ultimately, co-optimisation promotes the long-term benefit of consumers by ensuring SPD trades-off all resources in finding the

[22] Orion's (2019) query relates to the potential for 'multiple risk-setters', discussed at length in our 2019 paper.

[23] See ERCOT's Real-Time Co-Optimization Task Force at http://www.ercot.com/committee/rtctf.

dispatch solution at least total cost. That means optimising the costs of energy, reserves, and the dynamic level of risk (ie, the supply sources that reserve is scheduled to cover). Co-optimisation allocates resources to their highest-value use, based on the current conditions on the power system. Removing co-optimisation would lead to less efficient use of resources and higher costs for New Zealand consumers.

4.98 Turning to the risk-violation model itself, we note the current 'reserve deficit' model has significant shortcomings. If used under RTP, energy prices could be suppressed during reserve shortfalls when multiple sources of risk are scheduled, sending a perverse signal. We detailed this and other problems in section 4 of our 2019 paper. We recognise the risk-violation curve is a new approach, and participants need time to become more comfortable with its use (see paragraph 8.5). But we consider it provides a robust and innovative solution that strengthens efficiency in the wholesale market while enabling RTP to meet its design objectives.

4.99 Orion (2019) also raised the interaction of energy and risk-violation prices making energy prices 'materially higher than the highest dispatched energy offer'. It suggested this was not consistent with the rationale for scarcity pricing, as 'a cost of non-supply'. It also stated the *cost* of such non-supply shouldn't exceed the value of energy not supplied.

4.100 Nodal prices can and do exceed the price of the highest cleared energy offer under normal conditions today. This reflects the additional marginal costs of providing reserve, transmission losses, and adhering to system constraints to supply additional energy at that node. The important point is that the price at a given node indicates the lowest incremental cost to supply an *extra* MW at that node, accounting for the effect on total system cost. This principle applies both during normal conditions and during scarcity, and will continue to apply under RTP. The cost of supplying that extra MW can then be greater than the cost of non-supply. Default scarcity pricing under RTP provides an alternative to supplying the extra MW at each node: instructed load shedding at those prices. The risk-violation curves extend this principle by supplying further alternatives: shortfalls in reserve. SPD compares all of these alternatives, using the lowest-cost option to meet the extra MW. The energy price at the node reflects the alternatives SPD chooses.

4.101 All 6 submitters responding to question 10 in our 2019 paper also agreed the risk-violation model does not increase incentives or opportunities for gaming. We will ensure the trading conduct provisions in the Code consider the risk-violation curves under RTP (see section 7).

The price for scarcity in FIR will be slightly higher than for SIR

2019 paper paragraph(s):	4.41 – 4.45	on page(s):	31 – 33	and question:	9
UPHELD as proposed					

4.102 There will be two separate risk-violation curves, one for each reserve product: fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR). Each risk-violation tranche will use a slightly higher price for FIR than for SIR. As detailed in our 2019 paper, this reflects the relatively higher risk of triggering AUFLS in a contingent event if FIR is short. Or equivalently, that FIR has greater value in arresting potential frequency collapse.[24]

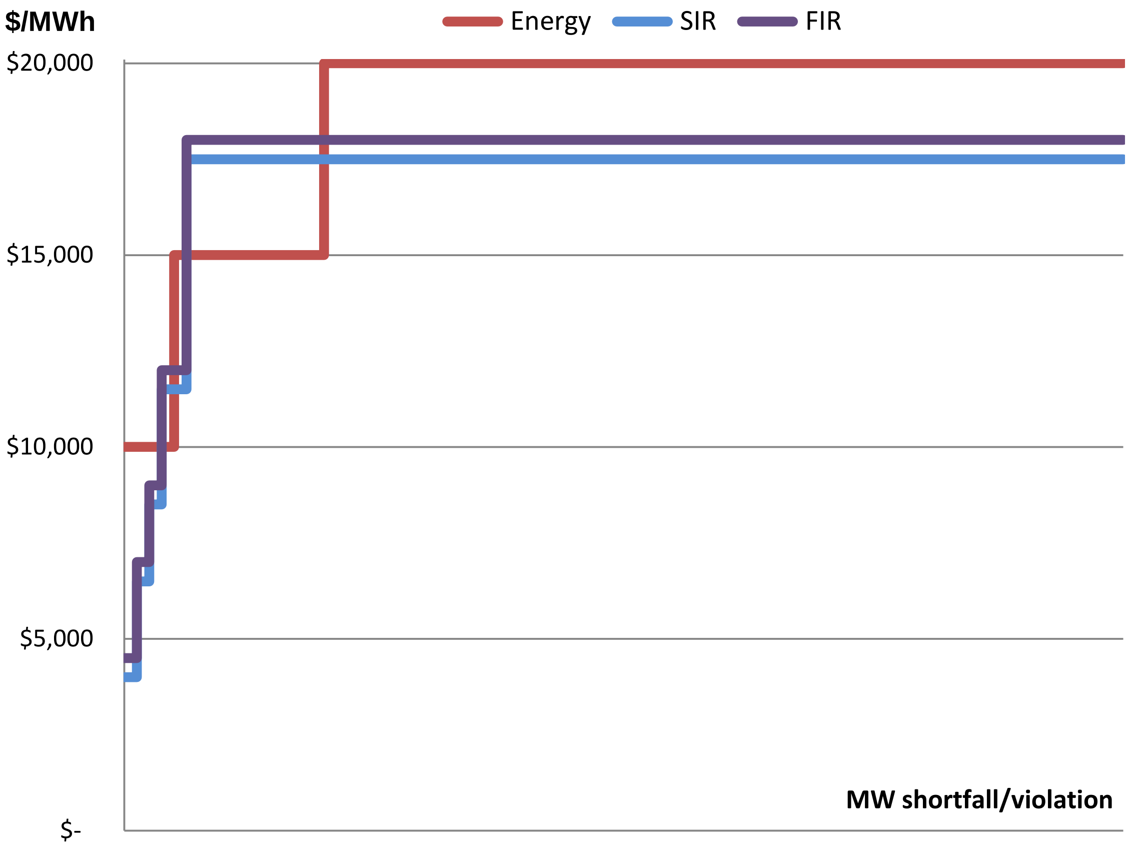
4.103 In general, a higher risk-violation price for a shortfall in FIR relative to SIR:

(a) favours a SIR shortfall ahead of FIR shortfall, all other things being equal

(b) sends a price signal during reserve scarcity reflecting the greater value of FIR relative to SIR.

4.104 The full risk-violation curves are illustrated in Figure 8, with the default scarcity pricing blocks shown as stepped quantities of rising energy shortfall (quantity of load shed).

Figure 8: Pricing energy shortfalls and risk-violation under RTP



Source: Electricity Authority

Notes: The default scarcity pricing blocks (red) are shown as a progressive quantity of energy shortfall.

Our response to submitters' views

4.105 All 7 submitters responding to this question in our 2019 paper supported a slightly higher risk-violation price for FIR than SIR.

4.106 Mercury (2019) agreed, but argued this relative preference should be 'reviewed regularly as market conditions are likely to change over time and in the future the relative value of FIR and SIR may change'. We will review these price values as part of the overall review of scarcity pricing, as detailed in section 6. The relative preference could change over

24 As noted by Transpower in its 2019 submission.

time through that process. But we regard this as unlikely, given it reflects the physical characteristics of contingency frequency response.

The risk-violation curves will not limit the total quantity of reserve shortfall

2019 paper paragraph(s):	4.71	on page(s): 44 – 45	and question: 13
REVISED			

4.107 The final tranche for the FIR and SIR risk-violation curves will be unlimited. The total quantity of reserve shortfall under RTP will therefore not be capped by these curves. All available reserve can then be used to supply energy instead (where it offers into both energy and reserve markets).[25]

How this changed from our proposal

4.108 The risk-violation curves we proposed in our 2019 paper set a finite quantity in the final tranche. The sum of all tranche quantities in each curve therefore strictly caps the total possible reserve shortfall in each reserve class (at 150 MW in the version we proposed).

4.109 Of 6 submitters responding to this question in our 2019 paper, only Genesis (2019) supported a finite limit. It argued this signals a point where load shedding should occur, though that point is necessarily arbitrary. Genesis (2019) also noted this might conflict with the system operator's principal performance obligations.

4.110 Mercury (2019), Meridian (2019), and Transpower (2019) all preferred no limit on the quantity of reserve shortfall. Removing the limit would prioritise sacrificing all available reserve ahead of load shedding at the final default scarcity pricing block (at $20,000/MWh). This is the same as current practice — but prices today will not reflect the extent of that scarcity.

4.111 Contact (2019) and Trustpower (2019) did not state a position.

4.112 We agree the final risk-violation tranches should be unlimited. We note Transpower's position in its 2019 submission:

> We consider the current industry-preferred practice should continue i.e. to redispatch all spinning reserve as energy and rely on interruptible load and AUFLS to manage a contingent event during a shortfall.

4.113 However, for clarity the risk-violation curves cannot guarantee reserve is sacrificed ahead of load shedding. For example, load shedding at the $20,000/MWh block would be cheaper than incurring shortfalls in *both* FIR at $18,000/MW/h and SIR at $17,500/MW/h (using the values listed in Table 4 below).

Our response to submitters' views

4.114 Contact (2019) stated more work was required on this question, to determine 'what the minimum quantity is to avoid cascade failure of the grid'. To clarify — and as stated by Transpower above — reserve shortfall will only ever be permitted for 'contingent event' risks. By definition this means AUFLS will be sufficient to arrest the frequency deviation

25 Interruptible load (IL) cannot be used to supply energy instead, so in practice reserve cover will still be provided by offered IL.

and avoid cascade collapse if a contingent event occurs. No reserve shortfall will be permitted if the ‘*extended* contingent event’ risk is binding, the same as current practice.

We have retained the ‘lower price’ risk-violation curves in the Code amendment, but will review this before RTP goes live

2019 paper paragraph(s): 4.55 – 4.71 on page(s): 37 – 44 and question: 12

UPHELD as proposed

4.115 The risk-violation curves illustrated in Figure 8 show the ‘lower price’ version we proposed in our 2019 paper, with the final tranche quantity now unlimited. The Code amendment attached as Appendix A uses this configuration, shown in Table 4.

Table 4: Current risk-violation curves in RTP Code amendment

Tranche	FIR price ($/MW/h)	SIR price ($/MW/h)	Quantity (MW)
1	4,500	4,000	10
2	7,000	6,500	10
3	9,000	8,500	10
4	12,000	11,500	20
5	18,000	17,500	*No limit*

4.116 Using these risk-violation curves, reserve prices will move through an intermediate step — elevated for a limited initial level of reserve shortfall, but not yet at full scarcity levels. This allows a degree of risk-violation before the price rises to signal ‘emergency’ conditions. The three intermediate tranches (priced below the first default scarcity pricing block at $10,000/MWh) define the pace of that rise. Reserve shortfall is more likely ahead of load shedding, and both FIR and SIR violation can occur at those intermediate prices. Reserve and energy offered above these tranche prices would not be scheduled initially, but this restraint persists only for the reasonably small size of the first tranches.

4.117 However, we stress there is no perfectly ‘right’ answer, given the complex trade-offs explained in our 2019 paper. Other risk-violation curves are equally viable. We will further consider the risk-violation curve configurations when we review the scarcity pricing values before RTP goes live (see section 6). SPD’s model formulation will be able to accept any configuration for the risk-violation curves, and these can be revised in future without further system changes.

Our response to submitters’ views

4.118 Genesis (2019), Meridian (2019), and Trustpower (2019) agreed we should adopt the ‘lower price’ configuration of the risk-violation curves proposed in our 2019 paper. Meridian (2019) stated it is ‘sensible to increase the chance of reserve shortfall before energy deficit and thereby constrain prices’, and that the proposed prices are ‘sufficient to signal scarcity’.

4.119 Transpower (2019) did not state a view on the risk-violation curve configuration directly, but supports one that reduces the risk of instructed load shedding. We consider the 'lower price' version is consistent with Transpower's position.

4.120 Mercury (2019) preferred an alternative configuration with higher prices, using lower volumes across a greater number of tranches. Mercury argued this 'incentivises all energy and reserve offers to clear ahead of any trigger for shortfall pricing'.

4.121 While more tranches would make the risk-violation curves more granular, using higher prices is likely to result in more load shedding. This is because the first default scarcity pricing block would now more likely be lower cost than violating multiple risk sources, or violating both FIR and SIR simultaneously.[26] More generally however, extra tranches may mean a smaller degree of reserve shortfall before clearing higher-priced energy and reserve offers. This potential benefit will need to be balanced against a more complex configuration. We will consider this question during further engagement with industry during RTP's build phase.

4.122 Contact (2019) stated it was unable to judge the proposed risk-violation configuration until the Authority reviews the scarcity pricing values under RTP. It noted the first tranches are priced below historic energy offers for last-resort generators such as Whirinaki. Contact (2019) argued this can potentially lead to 'emergency generation not being dispatched in favour of running the grid in a less secure state'.

4.123 We accept Contact's (2019) concern. There are inevitable trade-offs in defining the risk-violation curves. Setting higher risk-violation tranche prices would make generation such as Whirinaki more likely to be scheduled ahead of reserve shortfalls. But this has drawbacks. It would also mean reserve shortfall is now less likely than load shedding in other scenarios, and that FIR or SIR risk-violation could occur individually, but not both.[27] Setting the first tranche to a reasonably small quantity (at 10 MW) also means this restraint on offers is relatively minor.

We will not introduce a new type of formal notice for reserve shortfalls, but the system operator is changing its processes

2019 paper paragraph(s):	4.72 – 4.73	on page(s): 45	and question: 14

UPHELD as proposed

4.124 We have decided not to require a new type of formal notice in Technical Code B of Schedule 8.3 of the Code for reserve shortfalls under RTP. As stated in our 2019 paper, we consider existing notices are adequate for this purpose.

4.125 However, the system operator has recently independently changed its operational practices for communicating with participants when shortfalls situations are developing. It has begun issuing new 'low residual situation' customer advice notices (CANs). These occur when the forward schedules show offered quantities of generation and instantaneous reserve may not meet demand for energy and reserve.[28] The system

26 See pages 38 and 39 of our 2019 paper.

27 In highly simplified terms, if the first tranches were raised to $5,000/MW/h, violating the risk of both FIR and SIR would not be cheaper than the first default scarcity pricing block at $10,000/MWh.

28 More information is available on the system operator's website at https://www.transpower.co.nz/system-operator/operational-information/notice-low-residual-situations.

operator is currently trialling this new notice policy, and will assess whether it should continue under RTP. The system operator also issues standby residual check (SRC) notices for a similar purpose. These can be updated as part of RTP to provide further relevant information.

Our response to submitters' views

4.126 Four of 5 submitters responding to this question in our 2019 paper agreed a new formal notice is not required.

4.127 Mercury (2019) disagreed, arguing better information would support greater participation from new, smaller participants. While we agree with Mercury's justification, we consider the existing framework complemented by the system operator's increased use of CANs can meet this need. We may consider introducing a new formal notice in future if operational experience under RTP indicates this is not sufficient.

4.128 Genesis (2019) agreed existing notices are sufficient, but raised its concern around visibility of those notices. Genesis noted the system operator may only communicate GENs to specific participants it considers relevant, which 'excludes other participants being able to manage risk'.

4.129 We accept Genesis' point and agree GENs should be more visible more quickly under RTP. We expect the volume of operational and commercial information will increase under RTP generally. We will consider how best to communicate that information to participants during RTP's build phase. That may involve making greater use of the system operator's existing facilities.[29] However, the system operator may continue to 'target' GENs to participants in locations with resources best able to help manage grid emergencies. Regardless, we will ensure GENs are communicated appropriately to all participants.

Genuine high spring-washer pricing situations occurring in dispatch prices will not be modified

2017 paper paragraph(s):	3.60 – 3.61	on page(s): 28 – 29	and question: 10

UPHELD as proposed

4.130 The system operator will update its operational procedures and real-time monitoring tools to reduce the risk of model inaccuracies causing high spring-washer prices under RTP. Real-time monitoring can indicate whether potential high spring-washer dispatch prices are accurately reflecting system conditions. If real-time monitoring indicates the model is not accurately reflecting system conditions, the system operator may adjust the relevant binding transmission constraint(s). The system operator would then produce a new dispatch schedule, which should alleviate high spring-washer dispatch prices that were not genuine.

4.131 There will be no intervention to modify or remove genuine high spring-washer prices in dispatch schedules. Dispatch prices at the high-price end of a spring-washer transmission constraint will be limited by the default scarcity pricing values. Dispatch prices at the low-price end will not be limited directly, but will naturally be restrained by

[29] For example, receiving notices by subscribing to the system operator's *Operational Information* webpage at https://www.transpower.co.nz/system-operator/operational-information.

the high-price end. Dispatch prices at the low-price end of the spring-washer could be negative, as they can be today.[30]

4.132 More detail is provided in the system operator's technical report attached as Appendix E.

Our response to submitters' views

4.133 Eight of 9 submitters responding to this question in our 2017 paper supported removing the current Code provisions that adjust final prices if a high spring-washer pricing situation is deemed to occur. Submitters agreed these provisions do not translate to pricing in real-time, though wanted further analysis on the potential for high spring-washer prices under RTP.

4.134 Trustpower (2017) agreed in principle, but suggested applying a similar price ratio to current provisions ex-ante, rather than ex-post. Mercury (2017) disagreed, stating 'sensitivities in SPD' could result in 'erroneous' high spring-washer prices set by default scarcity pricing.

4.135 Subsequent to our 2017 consultation, the system operator conducted further technical investigation into the treatment of high spring-washer pricing situations under RTP. Its report is attached as Appendix E. Given that investigation, we consider:

(a) High-spring washer pricing situations are caused by security constraints reflecting complex physical loop flows on the transmission system. They are legitimate nodal pricing outcomes today and will remain so under RTP.

(b) Attempting to modify dispatch schedules to remove apparent high spring-washer prices directly threatens system security by interfering with those constraints.

(c) RTP will use more accurate demand metering inputs to the dispatch schedule (see paragraph 4.137), reducing the scope for underlying SPD model inaccuracies.

(d) As outlined in paragraph 4.130 above, the system operator will also seek to validate apparent high spring-washer pricing situations in real-time. The system operator's post-schedule check (PSC) tool will include tests for high prices, price ratios, and binding constraints. The PSC results will prompt the system operator to consider the accuracy of the dispatch schedule compared to real-time system conditions. Re-dispatching after adjusting transmission constraints to reflect real-time system conditions may alleviate high spring-washer prices.

(e) However, it is not possible to reliably detect high spring-washer pricing situations (as they are currently defined in the Code) in the timeframes relevant to dispatch. The test in the existing Code is only an indication a high spring-washer occurred.[31] It requires extensive manual analysis to confirm whether the binding constraint should be relaxed to remove the spring-washer price effect. Applying an ex-ante limit on dispatch price ratios (as Trustpower suggested) therefore risks both false positives and false negatives.

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30 The system operator's educational video series explaining spring-washer pricing effects on the transmission system is available at https://www.youtube.com/watch?v=pezUSbI9OUY.

31 The current test for a high spring-washer pricing situation is one of correlation not causation. Independent tests for price ratios and binding AC constraints must both fail to deem the situation a high spring-washer. This can suggest spring-washers are occurring when they are not, commonly due to reserve co-optimisation; and suggest none occurred when they do, such as when a high marginal offer price elsewhere in the grid 'invalidates' what would otherwise be a high spring-washer.

(f) In contrast to current ex-post pricing, any high spring-washer dispatch prices will be visible in real-time and participants and consumers can react to those prices. That response can ease the binding transmission constraint(s), leading to lower subsequent dispatch prices.

(g) Transient high spring-washer prices will be moderated in final spot prices through the time-weighted averaging process; ie, if they occur for part of the trading period. In contrast, high spring-washer prices today apply for the full trading period.[32]

4.136 On balance, we consider attempting to limit possible high spring-washer prices under RTP requires intervention that would be largely arbitrary and is not likely to be reliable.

Load at conforming GXPs in dispatch schedules will be forecast by a 'bottom-up' approach using the grid owner's ION meters

2017 paper paragraph(s):	3.67 – 3.72	on page(s): 29 – 30	and question: 11 & 12
UPHELD as proposed			

4.137 The system operator will upgrade its short-term load forecast (STLF) tool from its current 'top-down' process to a 'bottom-up' method, as noted in Box 1. The forecast of expected *net* load at each conforming GXP used in the dispatch schedule will now be based on current load at that node, metered in real-time.[33]

4.138 The primary data input to that forecast will be the grid owner's revenue-quality ION meters, which are more accurate than SCADA indications.[34] The load forecast used in dispatch will then be more accurate than the case today. If ION meter data for a node(s) is not available in real-time, the system operator's SCADA data validation (SDV) tool will automatically move to the next-best data source following a pre-defined hierarchy.

Our response to submitters' views

4.139 All 12 submitters responding to question 11 in our 2017 paper agreed with our proposal to move to a bottom-up load forecast. All 11 submitters responding to question 12 supported using the more accurate ION meters to do so.

4.140 NZX (2017) and Trustpower (2017) argued the system operator's process for calculating expected demand should be documented and published, providing valuable information to participants about the dispatch process.

4.141 We agree. The system operator will document and publish its STLF methodology as part of implementing RTP, and will refer to that methodology in the Policy Statement.

4.142 Orion (2017) stated it was unclear how a bottom-up forecast will be 'translated to required supply', as it did not include additional generation to offset transmission losses.

4.143 The wholesale spot market is a locational (nodal) marginal pricing system. SPD uses a loss-tranche model to calculate expected losses based on transmission branch flows

32 As noted in Appendix E, the current final pricing schedule is calculated using constraints in place at the start of the trading period. Any changes in the dispatch process during the trading period are not used.

33 The current process is less accurate, projecting conforming load from a current system generation, adjusted for losses and then distributed down to each node using historical load factors.

34 Supervisory control and data acquisition (SCADA) is an industry standard for remotely controlling and monitoring physical equipment. In this context, SCADA provides real-time telemetry showing the electricity output of a generator or the consumption of loads.

determined from load input and scheduled generation.[35] SPD dispatches generation optimised to account for all relevant losses. RTP in no way changes this core function of the dispatch process.

4.144 Orion (2019) also queried whether the system operator will dispatch from current metered quantities at each GXP, or some forecast of the underlying gross load. That is, account for the amount of demand response at that GXP.

4.145 For clarity, the system operator always dispatches for expected net load — the MW quantity to be supplied from generation resources on the grid in real-time. RTP does not change this fundamental requirement for operating the power system securely. Though moving to the bottom-up forecast should make the process for forecasting that net load more accurate. As explained in detail in our 2019 paper, *non-dispatched* demand response to real-time dispatch prices reduces net load. That reduced net load may then reduce the subsequent dispatch price (or avoid it rising higher).

Load at non-conforming GXPs in dispatch schedules will be a persistence forecast

2017 paper paragraph(s):	3.20, 3.70	on page(s):	19, 30	and question:	11
UPHELD as proposed					

4.146 The expected load at each non-conforming GXP used in the dispatch schedule will be determined by a persistence forecast: the current metered load at that node is simply assumed to persist at that same MW value for the next dispatch interval. Using the same process outlined in paragraph 4.138 above, the primary data input for this persistence forecast will be the grid owner's ION meters.

Our response to submitters' views

4.147 We consider all 12 submitters responding to this question in our 2017 paper agreed with our proposal.

4.148 However, we focussed on conforming GXPs when discussing the forecast load input to the dispatch process. Our explanation of how load at non-conforming GXPs will be determined lacked detail in the main body of our 2017 paper (though the information was in Appendix G). We consider this relative lack of explanation caused a degree of confusion for some submitters. EnerNOC (2017), NZS (2017), and WPI (2017) all raised concerns purchasers at non-conforming GXPs would be 'disadvantaged' under RTP. They considered these purchasers will in effect be prevented from reacting to dispatch prices, or be subject to onerous compliance rules.

4.149 To address those concerns and fully state how non-conforming GXPs will be treated under RTP, we confirm that:

(a) The obligations for purchasers at non-conforming GXPs do not change. They will continue to submit nominated non-dispatch bids under clause 13.7AA, the same as they do today.

35 The loss-tranche model is an exponential-like curve linearised into 6 loss tranches, calculated based on the physical attributes of the conductors and transformers in each transmission branch. Scheduled generation is therefore load + losses. It can be thought of as positive quantities (generation) being moved around the transmission grid to meet negative quantities (load), summing to zero. Losses are included as negative quantities incurred during transport.

(b) These bids serve two purposes:

(i) Because the system operator is unable to reliably forecast load for these purchasers, their bids state how much electricity they expect to consume. That quantity is used in determining the NRS forward schedule.

(ii) The prices in each bid also indicate the price levels at which purchasers may reduce consumption; ie, a statement of their price-response. Both the price and quantity values are used in determining the PRS forward schedule.

(c) These bids will be discarded for dispatch. They will play no role in the dispatch process and cannot set dispatch prices. The load quantity will be replaced by a persistence forecast of current metered load (as set out above). That load will be assigned to the default scarcity pricing blocks, the same as all other load not bid as dispatchable demand (or dispatch-lite).

4.150 This information is shown graphically in Table 5 and detailed in Appendix C.

Table 5: Treatment of non-dispatch bids for purchasers at non-conforming GXPs

Schedule process	Quantity input (MW)	Price input
NRS forward schedule	Non-dispatch bid	Scarcity pricing blocks
PRS forward schedule	Non-dispatch bid	Non-dispatch bid
RTD dispatch schedule	Persistence forecast	Scarcity pricing blocks

4.151 Purchasers at non-conforming GXPs are entirely able to react to dispatch prices under RTP. Their bids ought to reflect their expected price response, as noted above. In behaving according to these bids, purchasers will then alter their load based on dispatch prices: if the dispatch price exceeds their bid price, they would reduce load by the relevant quantity, and so on. In this way, purchasers at non-conforming nodes have full discretion to vary their load 'at will' by reacting to dispatch prices (or their expectation of the final price for the trading period).

4.152 Rebidding during the trading period will now be possible, so purchasers can revise their bids within gate closure under clause 13.19B (also see paragraph 4.167). Clause 13.19B does not require a bona fide physical reason. Further, non-dispatch bids also have a tolerance range for accuracy: clause 13.19B only *requires* purchasers to revise their bids if their expected load in the relevant price tranche will vary from the bid quantity by 20% or 20 MW (whichever is less). The relatively-new web services WITS API also makes rebidding easier by using modern software tools.

4.153 Given these arrangements, we do not consider purchasers at non-conforming GXPs will be disadvantaged under RTP. We intend to engage with purchasers further during RTP's build phase to help ensure broad understanding of these arrangements (see section 8). We may consider further revising the bidding provisions in the Code if that engagement shows these concerns persist. Finally, we note RTP will make inaccurate non-dispatch bids more obvious — we expect purchasers to reasonably reflect their anticipated price response in their non-dispatch bids.

Dispatchable demand will be dispatched from the real-time dispatch schedule, the same as generation resources

2017 paper paragraph(s):	3.73 – 3.78	on page(s): 30 – 31	and question: 13
UPHELD as proposed			

4.154 Dispatchable demand will now be dispatched as part of the real-time dispatch schedule, in the same way generators are today. Currently, instructions are issued from the NRS once for each trading period only, usually approximately 25 minutes before the start of that period. Under RTP, dispatchable demand purchasers will instead receive dispatch instructions they are expected to begin acting on immediately (the same as generators). They may receive a new dispatch instruction in each dispatch schedule.

4.155 Consequently, dispatchable demand will move to using the system operator's dispatch service directly. Purchasers will be able to receive dispatch instructions using either ICCP or web services (the same as generators).[36] The current bespoke interface for viewing dispatch instructions in WITS will be decommissioned.

4.156 We will not introduce extra components such as ramp rates or minimum cycle times to mitigate the potential for 'yo-yo' dispatch instructions under RTP.[37] We consider this is unnecessary, and would add complexity and cost for no real benefit.

4.157 Because final pricing no longer requires it, dispatchable demand purchasers will no longer need to provide metering data to the grid owner the next day. Clearing and settlement will continue to use monthly reconciled metered volumes.

Our response to submitters' views

4.158 Eight of 10 submitters responding to this question in our 2017 paper supported moving dispatchable demand to the real-time dispatch schedule.

4.159 MEUG (2017) and NZX (2017) queried related bidding provisions in our proposed 2017 Code amendment. MEUG (2017, 2019) and WPI (2017) also raised concern about yo-yo instructions, and if ramp rates and minimum cycle times should be used to address this.

4.160 Genesis (2017) responded (see below), but did not clearly state if it supported moving dispatchable demand to the dispatch schedule.

4.161 EnerNOC (2017) disagreed, raising concerns the proposal 'does not compensate dispatchable demand units in an equal manner to a generation unit'. EnerNOC also argued dispatchable demand lacks flexibility and has high compliance obligations relating to the lead time for instructions and the ability to rebid as conditions change.

4.162 By compensation equal to generators, we take EnerNOC to mean dispatchable demand purchasers being paid the spot price. We regard this as inefficient and unwarranted, as detailed in the 2018 update to our demand response principles.[38] In summary,

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36 These new dispatch communication protocols are being introduced by the system operator's DSE project (see footnote 15).

37 Dispatchable demand does not currently use ramp rates, so instructions are simply 'go to *X* MW'. Dispatch instructions when the participant is marginal can alternate between 'off' and 'on', commonly known as 'yo-yo'. Adding a ramp rate, combined with a minimum cycle time (ie, must stay off for *Y* minutes), could prevent yo-yo instructions.

38 The 2018 update of our demand response principles is available on our website at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/demand-

purchasers benefit from dispatchable demand by avoiding paying more for electricity than they are willing. They are compensated through constrained on and off payments, but only for any divergence between their bid price and the final spot price. RTP will not change any of these arrangements, only the mechanism for being dispatched.

4.163 Regarding flexibility, we recognise EnerNOC's point that RTP substantially reduces the lead time for acting on a dispatch instruction. However, we consider this change is both necessary to properly implement RTP, and brings benefits in its own right. While some purchasers may not easily be able to act without advance notice, the reverse is also true. For example, some industrial users will want to reduce consumption rapidly; more importantly, they do not want to stay off for long time periods. Further, evolving technologies enabling load to be more controllable — most obviously battery storage — could resolve this inherent tension. We consider options like batteries will be more prevalent by the time RTP goes live in late 2022.

4.164 Genesis (2019) commented the existing dispatchable demand arrangements are 'complex [and] jargon-laden'. Introducing ramp rates or minimum cycle times would only make this situation worse, further discouraging participation. Genesis (2019) considered potential 'yo-yo' dispatch is part of operating in the market, and can be handled by bidding multiple price-quantity tranches. However, Vector (2017) noted introducing ramp rates or minimum cycle times 'may have merits if it can minimise rebidding within the trading period which can cause price volatility'.

4.165 We broadly agree with Genesis (2017). We do not consider the extra complexity of ramp rates and minimum cycle times is justified. Many potential load sources are binary in their consumption: either on or off. New technologies can help those that need more time to act. We consider participants can deal with this issue through their bid structure. We will develop further guidance for participants during RTPs build phase to explain this in more detail.

4.166 Further, we also revised the Code amendment after considering MEUG's (2017) queries. In particular, we removed the requirement in clause 13.19A(3A): this would have forced purchasers to become non-dispatchable in a trading period if they revised dispatch bids in the trading period immediately prior. This restriction only makes sense for current arrangements, where purchasers are dispatched ahead of the relevant trading period. We also revised clause 13.19A to allow purchasers to become dispatchable inside gate closure if the system operator declares a grid emergency.

4.167 On balance, we consider dispatchable demand under RTP provides appropriate flexibility without undue compliance burden, addressing MEUG's (2017, 2019) concerns:

(a) Purchasers can withdraw from dispatch at any time by rebidding as non-dispatch under clause 13.19A(1)(aa)(i), including during the current trading period. They can use this right to handle a potential yo-yo instruction, if needed. They will not receive constrained on or off payments for that trading period.

(b) Purchasers can revise the MW quantities in dispatch bids at any time under clause 13.19B if their physical circumstances change, including during the current trading period.

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response/development/demand-response-principles-2018-update/. In particular, see pages 10–14 of the accompanying decision paper.

(c) We amended the requirement for purchasers to advise the system operator if these revisions occur from 15 minutes before the start of the trading period under clause 13.20. Purchasers and the system operator can now agree this is not required.

4.168 NZS (2017) also queried whether dispatchable demand bids state the price purchasers are *not* willing to pay, or the maximum price they *are* willing to pay. Prices in dispatchable bids are the maximum, because bids can be marginal and hence set spot prices. If a purchaser does *not* wish to pay, say, $5,000/MWh, they can bid at $4,999.99.

Dispatch participants can rebid or reoffer during a trading period

2017 paper paragraph(s):	3.87 – 3.93	on page(s): 33	and question: 15
UPHELD as proposed			

4.169 Participants will be able to rebid and reoffer during the current trading period (as part of the longer gate closure period). This is prohibited today under clauses 13.19A(1) and 13.17(1) of the Code.

4.170 For generators, any revision to offers within the trading period will only be permitted under a GEN or for a bona fide physical reason, under the same restrictions as today. For dispatchable demand purchasers, revisions to bids are also permitted as set out in paragraph 4.167 above. Note, changing prices in either bids or offers continues to be prohibited during the gate closure period for both purchasers and generators.

4.171 Dispatch prices will therefore be calculated based on current information during the trading period. Bids and offers should be revised if participants' physical circumstances change during a trading period — or if acting to increase supply under a GEN.

4.172 Allowing rebidding and reoffering addresses two problems with current arrangements:

(a) The system operator must apply manual constraints if a participant notifies a bona fide during the current trading period. Current ex-post final prices are still calculated based on bids and offers at the start of each trading period, regardless of any subsequent manual changes. It's also not possible to distinguish these manual overrides from the system operator's use of discretion to vary from a dispatch schedule.

(b) Generators cannot easily signal their willingness to provide extra supply in the event of a GEN. Under RTP they will be able to reoffer with increased capacity, and this updated information will be quickly available to the system operator (on the order of seconds).

4.173 We do not consider introducing this change risks manipulation of spot prices, given the restrictions on when and what participants can revise during the current trading period. Participants will be subject to any revised good trading conduct provisions under the Code, as detailed in section 7.

Our response to submitters' views

4.174 All 10 submitters responding to this question in our 2017 paper supported allowing rebidding and reoffering during the current trading period.

4.175 Mercury (2017) and Transpower (2017) noted the change improves on current manual processes, provides more accurate information, and should reduce the risk of errors. EnerNOC (2017) agreed the trading conduct rules are sufficient to prevent any gaming.

Constrained on and off payments will be calculated using the last bid or offer in a trading period

2017 paper paragraph(s):	3.94 – 3.95	on page(s): 34	and question: 16
UPHELD as proposed			

4.176 Payments for constrained on and constrained off situations will continue under RTP. Payments will now be calculated using the last bid or offer submitted for a trading period, accounting for the ability to rebid and reoffer during a trading period discussed above.

4.177 Dispatchable demand purchasers will not be eligible for constrained on and off payments if they change their bids to non-dispatch during a trading period.

4.178 We corrected errors in the formulae for calculating constrained payments for dispatchable demand in clauses 13.194(1A) and 13.204(aa) of the Code amendment.

Our response to submitters' views

4.179 Eight of 10 submitters responding to this question in our 2017 paper supported using the last good bid or offer.

4.180 EnerNOC (2017) disagreed, arguing the average bid or offer across the trading period should be used instead, though did not give explanation. NZX (2017) also proposed time-weighted averaging, to address its concern around perverse incentives stemming from large payments if participants change bids or offers under a bona fide.

4.181 We do not consider averaging would be superior, as doing so:

(a) would increase complexity

(b) would not easily account for participants changing the MW quantities in a given bid or offer tranche (eg, when increasing supply under a GEN)

(c) would not readily capture dispatchable demand purchasers changing from dispatch to non-dispatch bids (or the reverse, if responding to a GEN).

4.182 We also do not consider there is a risk of perverse incentives from revising bid or offer quantities under a bona fide (putting aside any trading conduct requirements). This is because the last bid or offer will reflect the reduced capacity, possibly zeroing the quantity of the higher-priced tranche(s). The constrained on and off calculations under the RTP Code amendment will not 'reward' any participant in this situation.

Manual claims of a pricing error will be retained, but the system operator will automatically check for errors in dispatch prices

2017 paper paragraph(s):	3.96 – 3.101	on page(s): 34 – 37	and question: 17 & 18
REVISED			

4.183 The ability to manually claim a pricing error will be retained under RTP. However, the system operator will automatically check for potential pricing errors before dispatching from a dispatch schedule. To do so, the system operator will enhance its existing post-schedule check (PSC) validation tool. The tests the PSC applies will be revised for RTP, to look for potential errors in dispatch prices. Based on PSC test results, the system operator may withhold publishing dispatch prices from that schedule, then recalculate it to address any errors. Ultimately however, any dispatch price visible on WITS and produced from a dispatch schedule used to issue dispatch instructions will be valid for calculating final prices.

4.184 Clause 13.69D of the Code amendment requires the system operator to verify the accuracy of dispatch prices, and specify how it will do so in the Policy Statement. The system operator will refer to its validation process in the Policy Statement for this purpose. It will also add a requirement to publish its validation criteria, and engage with industry to define them. Further information on the PSC tool is provided in Appendix F.

4.185 Further, pricing errors will be more rigorously defined in the Code under RTP, aligning with recent changes in operational practice under current arrangements.[39] Specifically, a pricing error will be either:

(a) using the wrong set of dispatch prices when calculating interim prices (eg, using a dispatch price that wasn't visible on WITS, or that applied for a different node)

(b) incorrectly calculating the time-weighted average of the correct set of dispatch prices as required by clause 13.134A of the Code.

4.186 This definition is consistent with the principle that the prices for settlement should be the ones visible for participants and consumers to act on in real-time. As is operational practice today, modelling errors or other incorrect inputs to SPD will be addressed as potential breaches of the Code.

4.187 To claim a pricing error under RTP:

(a) Once interim prices are published on WITS, a person can submit a claim of pricing error to the system operator up to 12:00 on the next business day. The system operator may also self-initiate an investigation.

(b) The system operator will publish a notice advising a claim has been submitted by no later than 13:00 that same day — this process will be automated.

(c) If the system operator decides to investigate a pricing error, it must report its finding to the Authority within 2 business days of receiving the claim.

(d) The Authority then has a further 2 business days to decide whether to accept or reject the system operator's finding. The Authority will notify the clearing manager of that decision.

(e) Finally, if a pricing error is found, the Authority will direct the clearing manager to recalculate interim prices using the specified set of dispatch prices (under clause 13.177). If no further pricing error is claimed, these revised interim prices become final as normal.

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39 The existing definition of pricing error in the Code refers to using 'an incorrect input' in calculating the final pricing schedule. We have recently confirmed that modelling errors that were nonetheless used in the dispatch schedule and carried through to the final pricing schedule do not constitute an incorrect input. In other words, the 'correct' input was used because it was the same input used in dispatch.

How this changed from our proposal

4.188 Our 2017 paper proposed two possible high-level options for pricing errors under RTP: retain the manual claim process, with some materiality threshold; or fully automated error checking.

4.189 However, many submitters independently suggested a hybrid approach: do both. We agree, and consider this option is superior. Automated checking reduces the chance of publishing dispatch prices based on schedule inputs that don't reflect actual system conditions (also see the discussion from paragraph 4.130). Retaining the ability to claim a pricing error helps assure participants and consumers that manifest errors in interim prices will be redressed.

Our response to submitters' views

4.190 EnerNOC (2017) supported an automated approach, noting the process must be well defined and transparent. Flick (2017) supported automation as generally preferable to manual processes. Genesis (2017) noted the approach to pricing errors is critical to avoid undermining the improved price certainty RTP will provide. In supporting the automated approach, it recommended focusing on addressing the causes of pricing errors. NZX (2017) also argued a manual process reduces price certainty.

4.191 Mercury (2017) favoured a manual process, to account for complex errors. It also argued the definition of pricing error under RTP needed to be reviewed as dispatch prices flow directly to interim prices.

4.192 Contact (2017), Meridian (2017), Orion (2017), Pacific Aluminium (2017), Transpower (2017), Trustpower (2017), and Vector (2017) all supported a hybrid approach (explicitly or by implication).

4.193 We consider the hybrid approach set out above balances all of these perspectives, as stated in paragraph 4.189. Consulting with affected parties on the system operator's PSC tests and publishing the test criteria makes the process transparent. The definition of pricing error under RTP further reduces the loss of price certainty.

The system operator will investigate claims of pricing error, and the Authority will decide the outcome of that claim

2017 paper paragraph(s):	3.102 – 3.105 on page(s):	35 – 36	and question: 19
UPHELD as proposed			

4.194 The system operator will investigate claims of a pricing error, as noted in paragraph 4.187. The Authority will consider the system operator's finding, and decide whether the claim is upheld or rejected. The cost of retaining the pricing manager purely for this purpose would not be efficient.

Our response to submitters' views

4.195 Seven of 10 submitters responding to this question in our 2017 paper agreed the system operator was the best choice, provided the Authority makes the final decision.

4.196 Contact (2017) and Trustpower (2017) preferred the Authority perform the role directly, to avoid any possible conflict of interest. EnerNOC (2017) preferred retaining the pricing manager to ensure the process is impartial.

4.197 We consider the system operator is the appropriate party, with the Authority making the final determination. In practice, the system operator assists the pricing manager investigate pricing errors today. The Authority has the expertise needed to critically assess the system operator's findings. The narrowed definition of pricing error described in paragraph 4.185 also makes this simpler.

4.198 We have also revised the Code amendment to address Meridian's (2017, 2019) observation that clause 13.173C prevented the Authority from overriding the system operator's rejection of a pricing error claim.

Interim prices will be determined by a 'fallback' list if there is a market system outage

2017 paper paragraph(s):	3.106 – 3.108 on page(s): 38	and question: 20
UPHELD as proposed		

4.199 Spot prices will be calculated using a pre-determined 'fallback' list of alternative price information, in the event of a market system outage. The priority order for the inputs to calculating interim prices will be as follows:

1. The last dispatch price published on WITS for the current trading period stands until the end of that period. This is consistent with the 'good until replaced' nature of dispatch prices described in paragraph 4.8.
2. If no new dispatch price is available for the start of any trading period, the most-recently published PRS price for that period applies.
3. If a PRS price applies from the start of the trading period in which a market system outage ends, it will be replaced by new dispatch prices when they are available. That is, the PRS price is used in calculating the interim price only for that part of the trading period it was in effect.

4.200 Provisions for constrained on and off apply as normal for any trading period affected by a market system outage.

Our response to submitters' views

4.201 All 12 submitters responding to this question in our 2017 paper supported using the fallback list as the most pragmatic solution for pricing during market system outages.

4.202 However, Contact (2017), Mercury (2017), and Meridian (2017) raised concern that repeated instances of falling back to PRS prices detract from the overall benefit of RTP. Meridian (2017) submitted the system operator's planned market system outages may occur too frequently or last too long, and recommended these should be minimised.

4.203 We share submitters' view that falling back to the PRS for planned outages to handle routine maintenance is not ideal. We agree doing so detracts from the overall principle of accurate real-time prices. We tasked the system operator with investigating potential changes to reduce or avoid the need for such outages. However, it advises:

(a) It actively seeks to minimise the number and duration of system outages, and schedules these for times when grid activity and prices are more stable.

(b) The current market system platform (designed in the early 2000s) is not an 'always-on' IT architecture, so outages for maintenance are unavoidable. That is, the market system cannot transparently switch over to back-up sites. Changing to an always-on architecture would require a major redesign of the market system, with significant time and cost implications.

4.204 We consider redesigning the market system architecture to avoid planned outages would unjustifiably delay implementing RTP, and add significant costs to the project. We will monitor the effects of planned outages after RTP is implemented, and may revisit this issue in future.

The forward schedules will be modified the same way as dispatch schedules

2017 paper paragraph(s):	3.109 – 3.112 on page(s): 38	and question: 21
UPHELD as proposed		

4.205 The PRS and the NRS will be aligned with the real-time dispatch schedules by applying all modifications detailed above. There are two exceptions:

(a) Similar to current practice, the use of information in non-dispatch bids differs between the three schedules, as set out in Tables 3 and 5.

(b) The PRS and the NRS will continue to use estimated load as an average over the 30-minute trading period, and therefore produce a single forecast spot price. There will be no attempt to estimate load at 5-minute intervals and hence no forecast of individual *dispatch* prices.

Our response to submitters' views

4.206 All 10 submitters responding to this question in our 2017 paper supported aligning the forward schedules as proposed.

4.207 We agree with EnerNOC (2017), Transpower (2017), and Trustpower (2017) there may be merit in looking at forecasting load at 5-minute granularity in future, but not for RTP.

The current indicative 5-minute and final pricing schedules will cease

2017 paper paragraph(s):	3.113	on page(s): 39
UPHELD as proposed		

4.208 The current indicative ex-post 5-minute 'real time price' schedule and the current ex-post final pricing schedule will be defunct under RTP. Both schedules will be discontinued when RTP goes live.

The loss and constraint excess will be divided according to the dispatch schedules

2017 paper paragraph(s):	3.114 – 3.118 on page(s): 39	and question: 22
UPHELD as proposed		

4.209 The loss and constraint excess (LCE) is the settlement surplus caused because the total value of spot market purchases typically exceeds the total amount paid to suppliers.[40] Schedule 14.3 of the Code breaks LCE into two portions each month. The majority is used to fund financial transmission rights (FTRs), and the residual LCE (along with proceeds from auctions of FTRs) is rebated to transmission customers.

4.210 RTP does not change these arrangements. However, to ensure the LCE can continue to be divided under RTP, the values currently sourced from the final pricing schedule must be replaced with alternative information. Under RTP, Schedule 14.3 will use the set of dispatch schedules in each month instead, applying time-weighting for the duration of each dispatch schedule. This approach is consistent with the underlying philosophy used to apportion LCE under current arrangements.

Our response to submitters' views

4.211 Ten of 11 submitters responding to this question in our 2017 paper supported replacing values from the current final pricing schedule with alternatives from dispatch schedules. Transpower (2017) stated it assumed the proposal would not affect the process for apportioning LCE for FTRs.

4.212 However, Transpower subsequently argued in its submission on our 2019 paper that we can avoid the cost of updating the FTR manager's system to implement this change. Transpower (2019) essentially proposes the FTR manager should instead take all LCE to use for FTRs, simply returning any unused amount as the residual. It argues this reflects the growth of FTRs to account for approximately 90% of LCE.

4.213 Transpower's (2019) proposal has merit, but we consider further investigation into the implications of this change in FTR allocation is required, beyond the scope of RTP. We have therefore decided to proceed with our proposed amendment to Schedule 14.3 at this time. That decision ensures all consequential design changes necessary to implement RTP are in place. However, we will consider investigating this proposal further during RTP's build phase, and may subsequently revise RTP's implementing Code amendment.

40 The surplus is caused by transmission constraints, and the effect of transmission losses on prices at GXPs.

5 We will introduce dispatch-‘lite’ to encourage smaller purchasers and generators to participate in dispatch

5.1 We will implement dispatch-‘lite’ as part of RTP, as proposed in our 2019 paper. Dispatch-lite makes it easier for smaller-scale purchasers and generators to participate in dispatch and hence the process for setting spot market prices. Dispatch-lite extends the existing dispatch ‘products’ for full offered generation and dispatchable demand. It adds the flexibility to accommodate uncertain future shifts in technology and electricity services to consumers during a critical time for the sector. By encouraging and supporting broader and more diverse participation in the wholesale spot market, we consider dispatch-lite strengthens the benefits we expect RTP will deliver.

5.2 By increasing participation by smaller-scale purchasers and generators, dispatch-lite helps increase the responsiveness of wholesale spot prices to participants. We do not have any particular expectation about the level of participation in dispatch-lite under RTP, but we consider it an important option to offer.

5.3 Dispatch-lite has three main differences for participants from existing arrangements:

(a) they can say ‘no’ when dispatched by the system operator in real-time (enabled by introducing new ‘dispatch notifications’ for the purpose)

(b) they can withdraw from the dispatch process and instead act as price-takers

(c) as a trade-off, they will not receive constrained on or off payments.

5.4 As in our 2019 consultation paper, we will refer to smaller-scale generation resources not required to participate in dispatch as ‘distributed generation’. In this broader sense, distributed generation could be connected to the grid, not only distribution networks.[41]

5.5 The features of dispatch-lite are summarised in Table 6, then elaborated in the sections below.

Table 6: Features of dispatch-lite for smaller-scale purchasers and generators

Feature	Generation	Demand
Eligibility	Up to 30 MW capacity, approved by system operator	No maximum capacity limit, but must be approved by system operator
Need for telemetry (SCADA)	Not generally required, though the system operator may require it in some circumstances	
Gate closure period	One trading period (30 minutes)	
Method of dispatch	Dispatch notifications (likely using web services over public internet)	

[41] The Code defined terms ‘embedded generation’ (used throughout the Code) and ‘distributed generation’ (used in Part 6) are both restricted to generation connected to distribution networks. As in our 2019 paper, we have noted any instances where these terms are used in their formal Code sense in this paper.

Feature	Generation	Demand
Method to say 'no' to dispatch[1]	Reoffering immediately with quantity of 0 MW until end of next gate closure period	Rebidding immediately as nominated non-dispatch bid until end of next gate closure period
Compliance	Assessed monthly retrospectively, comparing metered volume against dispatch notifications (except where saying 'no')	
Constrained on (or off) payments	Not eligible	
When bids/offers are required	Must submit offers for all trading periods	Must submit bids for all trading periods
Ability to withdraw from the dispatch process (outside gate closure)	Submit offer with quantity set to 0 MW for relevant trading periods	Submit nominated non-dispatch bids for relevant trading periods

Source: Electricity Authority

Both smaller purchasers and generators will be eligible at the system operator's discretion, and SCADA will not be mandated

2019 paper paragraph(s): 3.16 – 3.27 on page(s): 9 – 11 and question: 1 – 3

UPHELD as proposed

5.6 Participation in dispatch-lite will require the system operator's approval in all cases. The system operator will consider individual dispatch-lite applications against the general criteria below. More detailed criteria will be set out in the Policy Statement, and the system operator will engage with interested parties to develop them during RTP's build phase.

5.7 Smaller purchasers will be eligible to use dispatchable demand-lite as **dispatch notification purchasers** at any GXP. They must apply for approval as a 'dispatch-capable load station' (DCLS) using the existing process for full dispatchable demand in Schedule 13.8. There will be no set maximum capacity limit. However, when evaluating applications from larger load sources, the system operator will consider factors such as:

(a) the potential effect on system security from a DCLS (or from multiple DCLS at a single GXP) saying no to dispatch notifications

(b) whether the DCLS will provide SCADA (see paragraph 5.11).

5.8 The system operator may then decline an application, or require SCADA to participate in dispatch-lite. We may subsequently determine a maximum capacity limit for dispatchable demand-lite is warranted, after gaining operational experience.

5.9 A distributed generator exporting less than 30 MW will be eligible to use distribution generation-lite as a **dispatch notification generator** at any GXP. As detailed in our 2019 paper, this limit is based on current thresholds in the Code. The generator may be connected to either a distribution network or directly to the grid. They must apply to the system operator in writing under clause 13.3F of the Code amendment.

5.10 A distributed generator may be able to use dispatch-lite to meet an obligation imposed under clause 8.25(5) of the Code. Clause 8.25(5) allows the system operator to require an embedded generator (as defined by the Code) of greater than 10 MW to indicate its intended output. The system operator may require the generator to submit offers for this purpose — these offers could be as a distributed generation-lite. Similarly, grid-connected generators with capacity between 10 MW and 30 MW may also be able to use distributed generation-lite to meet their obligation to offer under clause 13.6.

5.11 SCADA telemetry will not be a standard requirement to participate in dispatch-lite. The system operator will modify the market system to account for dispatch-lite bids and offers in determining the expected load at each GXP. This ensures the accuracy of load forecasts at the GXPs where dispatch-lite participants are sited is not compromised (by avoiding double-counting, as detailed in our 2019 paper).

5.12 However, the system operator may determine SCADA is needed for larger load sources applying to participate as dispatch demand-lite. The system operator may also determine SCADA is required for some distributed generators, separate to any application to become dispatchable.

5.13 In all cases, the controllable load or generation source must be separately metered to participate in dispatch-lite, as is standard for all other forms of dispatch.[42] This is used to assess compliance with dispatch notifications each month (see paragraph 5.38).

Our response to submitters' views

5.14 All submitters responding to these questions in our 2019 paper supported the eligibility criteria we proposed for dispatch-lite. IEGA (2019) and WEA (2019) noted the current Code thresholds for generator obligations (ie, the 30 MW limit) have proven over time to operate successfully.

5.15 Enel X (2019) and Mercury (2019) agreed in principle, but wanted more detail on the criteria to make them clearer.

5.16 Placing more detailed criteria in the Policy Statement, and engaging with interested parties to develop them during RTP's build phase, addresses these concerns. It provides transparency and prevents the system operator making (or appearing to make) arbitrary decisions on applications to participate.

5.17 Enel X (2019) noted dispatchable demand-lite is only available to purchasers, the same as for dispatchable demand today. It argued dispatch-lite should be opened up to third parties, allowing them to engage with end consumers who wish to remain on fixed-price retail contracts for the bulk of their consumption.

5.18 We agree more choice for consumers is an important objective and would strengthen the benefits dispatch-lite can deliver. Our current work to allow consumers greater choice over their electricity services is directly relevant in this context. The innovative approaches being explored in our additional consumer choice of electricity services (ACCES) project may enable third parties to participate in dispatch-lite on consumers'

[42] Note this could potentially be implemented using separate register channels on the same physical meter. See our ACCES project noted below.

behalf.[43] We may consider further revisions to the dispatch-lite arrangements as the ACCES project develops.

5.19 Mercury (2019) raised concern the 30 MW limit may be too high, as substantial uptake by many smaller generators could have unintended impacts in aggregate. We recognise this is possible, but do not consider the risk warrants a lower limit at this time. However, we may include a criterion to enforce an aggregate limit at a GXP. This will be considered further in developing the more detailed criteria in the Policy Statement. We also note the counterfactual: the generators may be at the GXP either way, so limiting participation will likely make little practical difference to system security.

5.20 WEA (2019) supported the criteria, but stated 'aggregation of controllable load sources will become a core market activity as the investment in behind the meter capability and intermittent generation increases'. We have not made specific provisions for aggregation in dispatch-lite. However, we note resources behind a single GXP could be offered as a single 'unit', provided the system operator is satisfied they will perform as expected. More generally though, we consider modern technologies will make it much easier to coordinate multiple offers to achieve the same outcome. That is, using more sophisticated software and control systems to manage multiple resources, including their individual dispatch offers.[44]

5.21 Genesis (2019) raised the possibility of introducing a 'SCADA-lite' as part of introducing dispatch-lite. This would have reduced reliability requirements and a slower communication rate, making it less expensive than traditional SCADA equipment.

5.22 We consider a SCADA-lite may have merit, and we are interested in using modern IT solutions to reduce costs for participants. However, we consider this is outside the scope of RTP. Other work such as the Authority's project looking at new generating technologies may provide other opportunities to pursue this idea.[45] One option in future could be leveraging the system operator's new web services interface in its updated dispatch facility. The Authority and the system operator welcome further discussion in this area.

5.23 IEGA (2019) suggested dispatch-lite could include block dispatch of distributed generation connected to multiple GXPs. It argued this would make participation easier or lower cost by enabling third party aggregators to manage Code obligations.

5.24 The system operator will consider the potential to use the Code's existing arrangements for block or station dispatch for dispatch-lite during RTP's build phase. However, we note these do not provide for aggregation by a third party, as such. We also consider software technologies may be able to achieve similar outcomes, by coordinating the response and offering functions for multiple generators.[46] Participants could contract with a third party to act on their behalf for that purpose, without any need to further amend the Code.

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43 More information on the ACCES project is available on our website at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/acces/. One option we are exploring is a 'channel trader' model, where separate traders will be associated with individual meter channels at a customer's ICP (see https://www.ea.govt.nz/dmsdocument/25146-acces-project-update-ipag).

44 Further work may be needed to assess how such coordination would comply with existing asset owner obligations under Part 8 of the Code; eg, under clause 8.25(6).

45 See the *Participation of new generating technologies in the wholesale market* project on our website at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/participation-of-new-generating-technologies-in-the-wholesale-market/.

46 See for example Box 2 on page 13 of our 2019 paper.

Gate closure for dispatch-lite will be one trading period

2019 paper paragraph(s):	3.32 – 3.35	on page(s): 13	and question: 5

UPHELD as proposed

5.25 Gate closure for all dispatch-lite participants will be one trading period (30 minutes). This aligns with the existing gate closure period for embedded generators (as defined in the Code).

Our response to submitters' views

5.26 All 9 submitters responding to this question in our 2019 paper agreed gate closure should be 30 minutes.

5.27 Contact (2019), Genesis (2019), and MEUG (2019) also raised shortening gate closure to 30 minutes for all participants (ie, for full offered generation and full dispatchable demand). Contact (2019) noted potential inefficiencies from a larger number of participants with a shorter gate closure period: there would in effect be two classes of participants, bidding and offering based on price forecasts over different time horizons.

5.28 While we recognise Contact's (2019) concern, further market system changes would be needed to move all participants to 30 minute gate closure.[47] That would add cost and increase the time to implement RTP. We also note reduced gate closure could somewhat reduce price certainty. We may consider revisiting this question in future, but not as part of RTP.

Participants can say no to a dispatch notification by sending a dispatch response and immediately rebidding or reoffering

2019 paper paragraph(s):	3.28 – 3.31	on page(s): 11 – 12	and question: 4

UPHELD as proposed

5.29 Dispatch-lite participants will be able to say no to a **dispatch notification** issued by the system operator in real-time. To do so, dispatch-lite participants would:

(a) send a specific type of acknowledgement to the dispatch notification through the dispatch system

(b) then immediately rebid or reoffer as non-dispatchable (using the method set out from paragraph 5.50) for the remainder of the current trading period until the end of the next gate closure period.

5.30 We consider the dispatch service enhanced by DSE makes the first step straightforward. Similarly, we intend WITS to provide a specific web service API for rebidding/reoffering to say no to dispatch notifications. We expect the two steps can be readily automated in software.

47 This was identified during the *Shortened gate closure* project that moved gate closure to 1 hour; more information is available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/bid-and-offer-provisions-of-the-code/.

5.31 This process:

(a) ensures the most recent active bid or offer applying within the trading period accurately reflects the dispatch-lite participant's behaviour

(b) imposes a reasonable consequence for saying no to a dispatch notification (the participant must withdraw from the dispatch and price-setting process for a minimum time)

(c) gives a readily identifiable record of these instances

(d) ensures the system operator has immediate information on the participant's intentions through both the acknowledgement response to the dispatch notification and the revised bid or offer

(e) avoids the extra cost and complexity of building a facility for the system operator to instead exclude the relevant bid or offer from the dispatch schedule.

Our response to submitters' views

5.32 Eight of 9 submitters responding to this question in our 2019 paper supported using the two-step process as proposed.

5.33 Contact (2019) noted participants should be allowed several minutes to send their acknowledgement response. We revised the Code amendment to clarify dispatch-lite has the same 4 minutes to respond as other dispatch participants under clause 13.79.

5.34 Genesis (2019) disagreed, raising concern the two-step process was unnecessarily complicated and could be seen as a barrier to participation. It suggested rebidding/reoffering alone may give the system operator sufficient information.

5.35 We recognise Genesis's (2019) concern. But we expect the process will be automated in client software, taking advantage of the new web services interfaces to both the dispatch service and WITS.[48] Further, as dispatch-lite participants will be required to acknowledge dispatch notifications in general, we do not regard this specific process for 'saying no' unduly increases complexity. However, we may revise this requirement during RTP's build phase if interested parties raise serious concerns.

Participants should say no to dispatch notifications rarely, and cannot ignore them

2019 paper paragraph(s):	3.36 – 3.43	on page(s): 14 – 15	and question: 6
UPHELD as proposed			

5.36 Dispatch-lite participants have the right to say no to dispatch notifications, but cannot simply ignore them. Failing to follow a dispatch notification — without following the correct process to say no above — would be a breach of the Code.

5.37 The system operator will have the right to suspend or revoke a dispatch-lite participant's approval if they repeatedly say no to dispatch notifications. We will not set hard limits in the Code on how often or over what time period this will be assessed. Instead, the system operator will publish criteria in the Policy Statement for this purpose. We will

48 Some dispatch-lite participants may prefer to use the ICCP dispatch facility, though this requires a private dedicated communication link. Even here, automation should be readily available to cover both steps.

further develop these criteria with input from interested parties during RTP's build phase. We will review and may amend those criteria after gaining operational experience with dispatch-lite.

5.38 Because SCADA is not mandated, compliance with dispatch notifications will be assessed retrospectively using monthly reconciliation data (metered volumes). These volumes will be compared against the behaviour required by the relevant dispatch notifications, excluding those notifications the participant correctly declined.

5.39 Dispatch-lite participants can say no to dispatch notifications in the event their bid or offer is marginal; ie, it determines the dispatch price. In this scenario, the dispatch price based on that bid or offer will remain until the system operator produces a new dispatch schedule and hence a new dispatch price. We expect this will be reasonably quick, given the system operator will know the dispatch-lite participant said no to their notification. Because their bid or offer will now be non-dispatchable, the dispatch-lite participant cannot set the price in the new dispatch schedule.

5.40 Dispatch-lite will also be subject to the good trading conduct provisions in the Code (see more detail in section 7).

Our response to submitters' views

5.41 Eight of 10 submitters responding to this question in our 2019 paper supported dispatch-lite participants being able to say no as proposed, with compliance assessed monthly ex-post from metered volumes.

5.42 However, Enel X (2019) and Mercury (2019) wanted more guidance on how often is too often, and further consultation on these compliance criteria. Orion (2019) also argued compliance needs further specification. We consider specifying the criteria in more detail in the Policy Statement and engaging with interested parties to develop them addresses this concern.

5.43 IEGA (2019) supported the proposal but noted it assumed bona fide arrangements in place for full offered generation will also apply for distributed generation-lite. That is, bona fide would be 'part of the "rare" occasions when a dispatch-lite participant decides not to comply with a dispatch instruction'.

5.44 To clarify in response to IEGA (2019):

(a) Dispatch-lite participants can still claim a bona fide physical reason, for example to change the MW quantity in their offer during gate closure.

(b) But a bona fide is different to saying 'no' under dispatch-lite. Saying no is declining a dispatch notification for *any* reason, provided this is done correctly. In this case the quantity must be revised to 0 MW, as detailed in paragraph 5.50(b).

5.45 Meridian (2019) supported the proposal, but requested we consider reporting instances where dispatch-lite participants say no to dispatch notifications to aid transparency. We agree publicly reporting on this aspect of dispatch-lite compliance will provide important information to participants. We will establish appropriate reporting using aggregate statistics as part of implementing RTP.

5.46 Genesis (2019) did not explicitly disagree with our proposal, but noted the system operator will have to administer different compliance rules for multiple participants. It recommended the system operator 'should consider whether it has the appropriate resources and capability' to do so.

5.47 We accept Genesis' (2019) concern. The system operator and the Authority are confident the system operator has the resources and expertise for this task. We also expect monitoring will be largely automated. The system operator would investigate further using data or manual log entries if warranted, the same as it does now.

5.48 Orion (2019) raised concern that assessing compliance would be 'problematic' unless dispatch-lite participants' load or generation sources are separately metered. It also argued separate metering could allow participants to reconnect those sources to an alternative metering point instead of responding as directed.

5.49 We confirm separate metering is a standard requirement for participating in dispatch, as noted in paragraph 5.13. Regarding Orion's (2019) second concern: we agree a participant bypassing metering for dispatchable resources is unacceptable. The system operator considers the potential to bypass metering as part of assessing applications to participate in dispatch.[49] This will also apply to dispatch-lite. We also note purchasers would have little to gain from doing so in practice: reconnecting load they had nominally turned off would mean they end up paying the higher dispatch price anyway. Logically they should simply bid a higher price. Even if the purchaser happened to be marginal, any benefit from setting a transient lower dispatch price would be minimal (and would not be worth the effort). The not-reduced net load would result in a higher dispatch price shortly afterward. Finally, such behaviour is also unlikely to meet the standard for good trading conduct.

Participants can elect to be non-dispatchable, and are required to do so when saying no to a dispatch notification

2019 paper paragraph(s):	3.44 – 3.48	on page(s): 15 – 16	and question: 7
UPHELD as proposed			

5.50 Dispatch-lite participants can become non-dispatchable for any trading period (subject to gate closure) by:

(a) purchasers submitting a 'nominated non-dispatch bid'. This bid type is already in place for the existing full dispatchable demand, and ensures the participant is removed from the dispatch process

(b) distributed generators reoffering with a quantity of 0 MW. The market system will subsequently dispatch a new output target of 0 MW.[50] A generator becoming non-dispatchable is thereby distinguishable from being dispatched to 0 MW when priced out of merit; ie, when they offered a non-zero quantity at a higher price.[51]

5.51 Bidding or offering non-dispatchable in this way is required when a dispatch-lite participant says no to a dispatch notification, as set out in paragraph 5.29(b).

5.52 This ability to become non-dispatchable means dispatch-lite participants won't need to operate a '24/7 trading desk' or facilities. For example, they could choose to be

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49 See the system operator's DCLS approval guidelines on its website at https://www.transpower.co.nz/system-operator/electricity-market/dispatch-capable-load-station-setup.

50 The distributed generator will 'know' this new 0 MW dispatch notification was caused by reoffering with quantity set to 0 MW.

51 As noted in our 2019 paper, we consider introducing a new 'non-dispatch offer' purely to match arrangements for dispatchable demand would increase cost and complexity for no practical benefit.

dispatchable only during business hours; at other times, they would simply be price takers, operating entirely at their own discretion.

5.53 Combined with the right to say no to dispatch notifications — if they don't do so too often — the ability to withdraw from dispatch gives dispatch-lite participants a substantial degree of flexibility. We consider this helps address concerns that becoming dispatchable imposes unacceptable compliance costs and a loss of operational control.

5.54 Appendix D summarises the dispatch processes for dispatch-lite set out in the sections above.

Our response to submitters' views

5.55 Six of 7 submitters responding to this question in our 2019 paper agreed with the arrangements for withdrawing from dispatch as proposed.

5.56 Mercury (2019) did not explicitly disagree with our proposal, but raised concern about the potential impact of many participants withdrawing from dispatch simultaneously. We recognise this could increase the operational burden (such as greater use of frequency keepers at that time, or more frequent redispatch). But as we note above, the counterfactual is distributed resources reacting to dispatch prices, with no information about their intentions available to the system operator. On balance, we consider encouraging better coordination of these resources through the dispatch process is superior. The system operator may also modify its procedures for evaluating supply risks if the volume of dispatch-lite grows substantially over time.

Most submitters to our 2019 consultation supported implementing dispatch-lite as part of RTP

5.57 Contact (2019), Enel X (2019), Genesis (2019), IEGA (2019), MEUG (2019), Trustpower (2019), and WEA (2019) supported introducing dispatch-lite as proposed. WEA (2019) emphasised its support for extending dispatch-lite to smaller-scale generation, as this strengthens RTP by 'better accommodating future shifts in technology'.

5.58 Contact (2019) queried whether the worked examples given in Appendix D of our 2019 paper apply to all loads, noting some need several hours downtime after being dispatched off. Our examples were intended only to illustrate the underlying concepts. Relatively inflexible loads may not be well suited to participating in dispatch; though technologies like battery storage may be able to reduce this downtime to an extent. We discussed this issue above from paragraph 4.163.

5.59 Orion (2019) supported extending dispatch-lite to include smaller-scale generation. However, Orion stated the only advantage it could see for participating in dispatch-lite is the dispatch notification, rather than simply reacting to dispatch prices. We agree the dispatch notification itself could be valuable for some parties; though under RTP dispatch prices accessible through WITS interfaces will play a similar role. The principal advantage of dispatch-lite is better price certainty and, in particular, being able to *set* dispatch prices. Our 2019 paper explains this in detail on page 18, illustrated with simple worked examples in Appendix D of that paper.

5.60 Mercury (2019) and Meridian (2019) did not support implementing dispatch-lite as part of RTP. Mercury (2019) reiterated its 'strong support' for RTP 'on its own merits', noting dispatch-lite is 'nice to have' but is not a pre-requisite. Meridian (2019) viewed dispatch-lite as a separate proposal that should only be progressed once RTP has 'bedded in'. It argued dispatch-lite risks complicating the already complex transition to RTP, and this could outweigh any benefit of implementing them simultaneously.

5.61 We accept these concerns. We recognise the benefits of RTP do not depend on dispatch-lite, and introducing it simultaneously does add a degree of complexity. However, on balance we consider the flexibility dispatch-lite brings could have significant value, and waiting to implement it after RTP would be a missed opportunity. Implementing dispatch-lite separately also adds cost relative to doing it as part of RTP. Most importantly, it risks leaving a growing number of distributed resources outside the dispatch process, by not lowering barriers to entry. Delaying dispatch-lite reduces certainty for third-parties in developing sound business cases for building new software platforms. Simply put, the pace of technological change means we could regret waiting to introduce dispatch-lite even one or two years after RTP goes live in 2022.

6 We will review the scarcity pricing values before RTP goes live, and at least every 5 years

6.1 As part of implementing RTP, we commit to reviewing all scarcity pricing values, including the risk-violation curves:

(a) before RTP goes live, most likely when consulting on the final form of the enabling Code amendment (see section 8)

(b) likely 1 and no more than 2 years after RTP goes live, to assess price outcomes and address any unexpected issues observed during operation. We also expect market behaviour will be heavily scrutinised by a range of stakeholders, as well as by the Authority and the system operator directly.

6.2 The methodology to determine the scarcity pricing values and the obligation to review them periodically once RTP is in operation are set out below.

We will adopt the methodology proposed in our 2019 paper for determining the scarcity pricing values

2019 paper paragraph(s):	5.1 – 5.6	on page(s): 45 – 46	and question: 15
UPHELD as proposed			

6.3 We will adopt the methodology set out in Appendix F of our 2019 paper for determining the default scarcity pricing values under RTP. That methodology continues the original approach we used when setting the current scarcity pricing values in the Code in 2011.

Our response to submitters' views

6.4 All 7 submitters responding to this question in our 2019 paper supported adopting the methodology proposed.

6.5 Contact (2019) agreed, subject to the methodology accounting for all new technologies and the 'true' value of lost load. We agree. The methodology will account for these factors; we will engage with interested parties further as part of the review process.

6.6 Mercury (2019) commented that we must maintain appropriate relativity between the default scarcity pricing values and the risk-violation curve parameters. We agree. As stated below, we will review all of these scarcity pricing components holistically.

The Authority will have an obligation in the Code to review the scarcity pricing values at least once every 5 years

2019 paper paragraph(s):	5.7 – 5.10	on page(s): 46	and question: 16

UPHELD as proposed

6.7 Clause 13.58AB of the Code will now oblige the Authority to conduct a review of the scarcity pricing values at least once every 5 years. That obligation explicitly specifies both the default scarcity pricing values, and the risk-violation curve parameters. We may also conduct a review at any other time, if we deem it necessary.

Our response to submitters' views

6.8 All 8 submitters responding to this question in our 2019 paper supported an obligation for the Authority to review the scarcity pricing values at least once every 5 years.

6.9 Mercury (2019) supported the obligation, but also stated it preferred more frequent reviews (such as biennial) to account for changing technologies and market conditions. Transpower (2019) noted too frequent reviews could prevent the market from forecasting future prices (ie, undermine longer-term investment).

6.10 We consider a 5 year review period is an appropriate balance between these considerations, and the time and cost required to conduct each review. Again, we can also review at other times if conditions warrant it.

6.11 Contact (2019) and Enel X (2019) also suggested it would be prudent to conduct a review 1 or 2 years after RTP goes live, to address any post-implementation issues. We agree, as stated in paragraph 6.1.

7 We will ensure trading conduct rules reinforce market confidence once RTP is implemented

7.1 Maintaining confidence in market outcomes under RTP will be vital to achieving the long term benefits we expect RTP will deliver. Alongside the Authority's market monitoring function, the Code's trading conduct provisions play a major role in ensuring that confidence. However, we recognise the current provisions have problems. In particular, is the 'high standard of trading conduct' required by clause 13.5A sufficiently clear, and does the 'safe harbour' provision in clause 13.54B promote that conduct? For that reason, we referred the trading conduct provisions to the market development advisory group (MDAG) for review in November 2017.

7.2 A major aspect of MDAG's review is a focus on trading behaviour causing spot prices to diverge from the efficient prices that would prevail under workable competition.[52] To achieve this, rules for good trading conduct may shift to explicitly prohibit or restrain particular forms of 'unwanted behaviour'.

7.3 MDAG's review is not yet complete, and the Authority has not yet made any decision to amend the trading conduct provisions in the Code. But we will ensure the trading conduct provisions are robust to the new arrangements and incentives RTP will introduce. We stress the Authority will continue to expect market behaviour to produce outcomes consistent with workable competition under RTP. Accordingly, we may further revise the RTP Code amendment in light of MDAG's review to explicitly identify new forms of unwanted behaviour, if RTP makes those possible. If circumstances warranted it, we can also amend the Code under urgency if unexpected trading issues arose.

7.4 We also highlight the important role of RTP itself in strengthening market confidence: it will greatly enhance the ability for demand to act as a countervailing force against attempts to manipulate spot prices. This is because prices are set by the behaviour not only of generator offers, but also of demand — either responding to dispatch prices, or bidding into the dispatch process directly. RTP dramatically increases the potential for demand response by providing 'real' prices visible in real-time. We are also introducing dispatch-'lite' to make it easier for demand to participate in the dispatch and hence price-setting process (see section 5).

7.5 Finally, trading conduct will remain subject to the undesirable trading situation (UTS) provisions in the Code. We also note participants may have broader legal obligations under other regulatory jurisdictions. A UTS investigation could then result in referrals to other statutory bodies.

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52 More information is available in MDAG's February 2019 presentation on trading conduct, available on the Authority's website at https://www.ea.govt.nz/dmsdocument/24904-trading-conduct-review.

8 We expect RTP will go live in September 2022

We will implement RTP in stages over the next four years

8.1 Implementing RTP requires information and communications technology changes to:

(a) the system operator's market system, including SPD and any changes needed to use the grid owner's ION meter data in real-time

(b) the clearing manager's system

(c) the reconciliation manager's system

(d) the FTR manager's system

(e) WITS.

8.2 It also requires disestablishing the pricing manager service provider role and its systems.

8.3 We will undertake this work in stages. Our current timeline is set out below, and illustrated in Figure 9:

(a) **by mid-2020:** all market systems design work is complete

(b) **by mid-2021:**

(i) service providers have developed their market system changes and integration-tested with other service providers

(ii) service providers have published their final specifications for the changes participants need to make to their own systems

(c) **from mid-2021:**

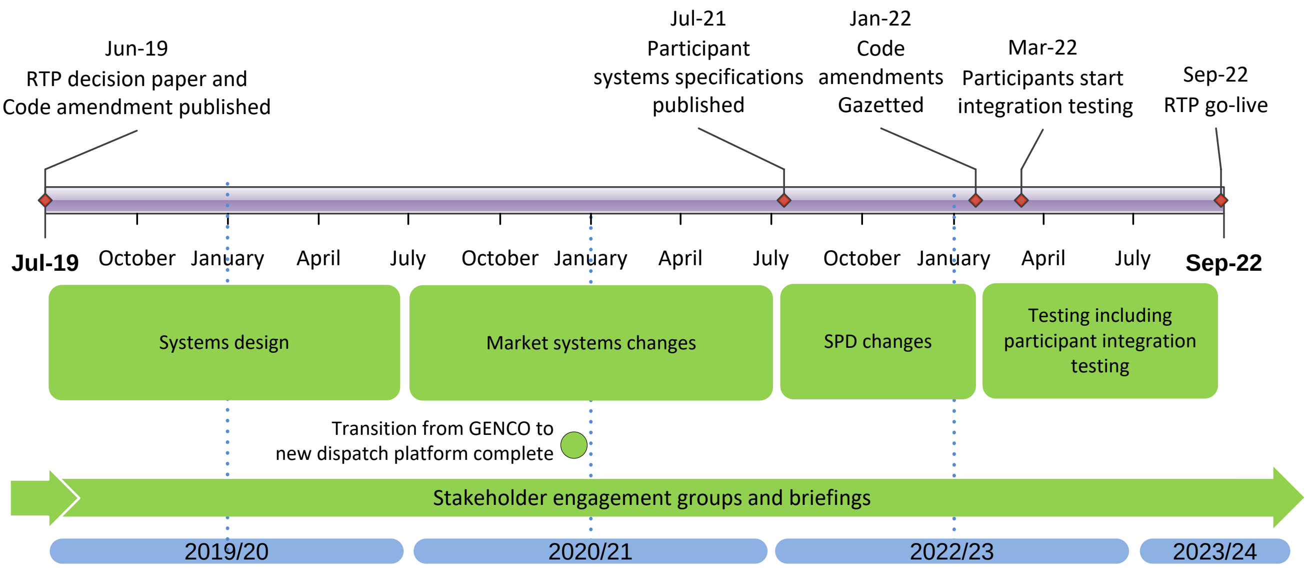
(i) the system operator deploys changes to SPD in preparation (as required to modify the forward and dispatch schedules) — *but no actual change to dispatch functions*

(ii) participants specify and begin their own internal system changes.

(d) **from early-2022:** service providers and participants begin full end-to-end testing of market and participant systems

(e) **September 2022:** RTP goes live.

Figure 9: RTP staged implementation timeline



Source: Electricity Authority

8.4 Generator participants may not need to change their systems substantially — offering and dispatch are broadly the same as today, except for reoffering within a trading period. However, dispatchable demand participants will need to:

(a) establish an interface to the system operator's dispatch service, to receive electronic dispatch instructions in real-time

(b) update their processes to use those dispatch instructions, rather than the current separate WITS interface approximately 25 minutes before the trading period.

We will engage with interested parties throughout the build process and continue that after RTP goes live

8.5 Ongoing dialogue between the Authority, service providers, and participants will be vital. We will use a series of engagement groups and public briefings to promote that interaction throughout RTP's build phase. These engagement groups are intended to:

(a) build more detailed understanding of how RTP will operate, especially for new approaches like the risk-violation curves

(b) enable industry experts to have input to the implementation detail of system and operational processes

(c) help validate more specific technical decisions on operational design

(d) provide a visible means of maintaining stakeholder buy in, and commitment to, delivering RTP effectively.

8.6 A number of parties have indicated this engagement process should continue after RTP goes live. We agree. Continuing that engagement enables participants and others to share operational experiences to help ensure RTP's benefits are realised.

We intend to Gazette the enabling Code amendment in late 2021

8.7 We will not Gazette the RTP Code amendment attached as Appendix A at this time. We consider this is prudent, because:

(a) Comprehensive Code amendments are required to implement RTP, particularly to the wholesale trading and spot price processes set out in Part 13. Other unrelated Code changes will inevitably occur during RTP's build phase. If we Gazette the RTP amendment now, we would need to revise it again to account for these.

(b) There are a number of matters we may decide to consult on further, to refine the implementation detail. For example, modifying the treatment of LCE for funding FTRs, as noted in paragraph 4.213.

8.8 We therefore intend to consult again on the final form of the RTP Code amendment, most likely in late calendar 2021. That consultation will incorporate our review of the scarcity pricing values, as detailed in section 6. We will then Gazette the final Code amendment once the go-live date is known with appropriate certainty.

It is not practicable to pilot RTP in parallel to the current pricing system

8.9 Our 2017 paper stated we intended to pilot RTP by publishing dispatch prices in parallel to the current pricing system before RTP goes live. Further detailed technical analysis has shown this is not practicable, would involve substantial extra cost, and is likely to be of limited use:

(a) Until RTP's Code amendment is in force, the system operator cannot apply the default scarcity pricing values or the risk-violation curves to the live system.

(b) Doing so then essentially requires an entire duplicate market system, including a parallel version of WITS.

(c) Any price or dispatch outcomes from the pilot RTP system would still use live bids and offers structured for pricing and dispatch under the current system. These outcomes may have little resemblance to real outcomes under RTP.

(d) Pilot RTP prices could create odd incentives for trading behaviour and settlement — some parties may respond to pilot dispatch prices, despite these having no bearing on current final prices.

8.10 On balance, we consider these drawbacks are substantial, and a pilot system would not be cost effective or of practical use.

8.11 However, we will further consider the practical benefit of publishing the existing RTD dispatch schedule during RTP's build phase. As Mercury (2017) noted, this could complement the current 5-minute indicative prices. One option could be publishing the RTD schedules with a delay, to avoid the cost of upgrading communications between the system operator and WITS to publish them in real-time.[53]

[53] The Authority's EMI platform already provides an API for a limited subset of information in RTDs. More information is available at https://emi.portal.azure-api.net/docs/services.

9 The amendment promotes our statutory objective

9.1 The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The amendment promotes all three limbs of our statutory objective

9.2 After considering all submissions on the Code amendment proposal, the Authority believes the Code amendment attached as Appendix A will deliver long-term benefits to consumers, as set out below.

Spot prices will be more actionable

9.3 Spot prices will become more actionable. That is, they will provide information that parties can act on in real-time with much greater confidence. Currently, parties use indicative prices, which can be unreliable predictors of spot prices. Further, indicative prices may not always be published in real-time, especially when the system is under stress.

Spot prices will be more resource efficient

9.4 Spot prices will be more resource efficient. For example, consumers will be less likely to later think they would have preferred to consume less or more at the spot price. Likewise, generators will be less likely to regret generating less or more than they did.

9.5 At present, there is greater scope for these inefficiencies because spot prices do not necessarily reflect the resources used in real-time, and current arrangements discourage some parties from participating in the spot market.

9.6 Spot prices that are more actionable and more resource efficient will promote all three limbs of our statutory objective through:

(a) greater competition among and between generators and consumers (via voluntary demand response or more participation in dispatch), especially when spot prices are high

(b) a more efficient level of reliability in the power system as the system operator could come to rely equally on dispatchable demand bids and generation offers

(c) a greater level of operational efficiency in the wholesale market as calculating spot prices will no longer require extensive manual intervention.

9.7 More actionable and reliable prices send clearer signals for efficient long-term investment. Improved price signals will remove barriers and promote uptake of new technologies and new business models. For example, clearer price signals during peak periods promote efficient investment in technologies like battery storage, smart appliances, or other forms of automated demand response. Investing in these technologies is currently stymied by calculating spot prices after the fact — RTP reduces the guesswork and improves investment certainty.

The amendment is consistent with the demand response principles

9.8 In June 2018, we published an updated version of the guiding regulatory principles that should apply to demand response initiatives.[54] Although RTP is not a demand response initiative per se, we expect it will provide significant benefits in this area. Table 7 assesses RTP's design detailed in sections 4 and 5 against the demand response principles.

9.9 Overall, we conclude RTP's design is consistent with the demand response principles.

Table 7: Testing RTP's design against the demand response principles

Guiding principle	Assessment
Best-possible incentives: incentives to undertake demand response should reflect the marginal benefit of that response to the electricity system. Any payment for providing demand response should be funded by those benefiting from that response.	✓ RTP will promote more efficient pricing outcomes for the reasons set out in paragraphs 9.3 and 9.4. Dispatch-lite will make it easier for smaller-scale purchasers and generators to directly influence spot prices. Purchasers participating in the spot market would not receive a payment for providing demand response but would avoid paying spot prices that exceed their willingness-to-pay by reducing consumption.
Openness: demand response should be able to participate in market arrangements, wherever practical. Anybody should be allowed to provide demand response services, including consumers and their agents. Demand response initiatives should not unreasonably restrict the technologies used to provide that response.	✓ More actionable spot prices under RTP will make it easier for consumers to participate in the spot market and react to spot prices in an efficient way. RTP does not restrict the technologies consumers can use to provide demand response. Dispatch-lite should enable greater participation in the spot market.
Choice: consumers should be free to choose when, how much, and by what technology they are willing to provide demand response, considering the costs and rewards they face. Consumers should be free to contract with third parties to provide demand response on their behalf. Any party buying demand response services should also be free to choose who, when, and how it is provided to them.	✓ Demand-response capability may be offered into the energy and reserve markets under RTP, and consumers can choose the most valuable use. RTP also allows dispatchable demand and dispatch-lite bids. Under RTP consumers are free to contract with third parties to provide demand response on their behalf.

[54] The updated principles are available at on our website at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/demand-response/development/demand-response-principles-2018-update/.

Guiding principle	Assessment
Transparency: arrangements for demand response should provide transparent information, enabling consumers and other parties to: (a) assess the potential value of offering demand response in its various forms (b) make sound decisions about offering and using demand response.	✓ RTP will improve transparency by providing more timely and actionable price signals to demand response providers. Participating in dispatch-lite will better reveal the intentions of smaller-scale purchasers and generators.

Source: Electricity Authority

The benefits of the proposal are greater than the costs

9.10 The Authority has assessed the economic benefits and costs of the amendment, as set out in our 2019 paper. We expect implementing RTP will deliver significant net economic benefit.

9.11 Consumers and generators that can alter their operations at short notice will have much more reliable price signals to act on. These signals can guide their decisions about when to consume or produce electricity — accurate price signals will also enable those processes to be fully automated. Even participants that need more time to react will benefit from real-time prices that are reliable. In contrast, participants currently need to wait at least two days before final prices are published.

9.12 We estimate implementing RTP will produce operational benefits with a present value of $62 million over 15 years in the base case. Those benefits are from avoided generation costs of $79 million, less additional demand response costs of $17 million.[55] Our analysis is based on quantitative and qualitative benefits from RTP in the following categories:

(a) more efficient levels of demand-response (industrial and commercial consumers)

(b) more efficient levels of demand-response (residential consumers)

(c) more efficient levels of reliability

(d) more efficient generation scheduling and dispatch

(e) more effective risk management

(f) increased overall market confidence.

9.13 Implementing RTP requires significant changes to the market systems. Some of the associated cost will be offset by savings to the pricing manager function. Participants may also incur some implementation costs. The present value of these combined costs is estimated to be $12 million.

55 The demand response cost arises because the variable costs consumers incur by using less electricity in response to dispatch prices can exceed the variable operating cost of the peaking generator being displaced. However, these costs to consumers are outweighed by the capital costs saved by avoiding investing in that peaking generator in the first place. For full details of our assessment of costs and benefits, see Appendix G of our 2019 consultation paper.

9.14 Overall, we expect RTP will produce net benefits with a present value of $50 million over 15 years in the base case. We also estimate net benefits in the upper and lower cases of $95 million and $15 million, respectively.

9.15 Section 6 and Appendix G of our 2019 paper details our assessment of these costs and benefits. That information superseded the earlier description of costs and benefits in our 2017 consultation, accounting for submissions on our 2017 paper. The revised quantitative cost-benefit analysis (CBA) from our 2019 paper is available at https://www.ea.govt.nz/dmsdocument/24931-revised-rtp-cost-benefit-analysis-model.

9.16 In its submission on our 2019 paper, MEUG queried whether our CBA assumes the full benefit of increased demand response under RTP occurs in the first year. It suggested while there may be many 'early adopters', others will wait to see how RTP progresses before committing resources to demand response.

9.17 We agree that demand response will develop over time. However, generation investment decisions are made over a long timeframe, and require predictions about future demand peaks. For this reason, we expect potential generation investments will be deferred once RTP is announced (even before implementation). We therefore consider the timing of savings from demand response in our CBA (avoided investment in generation) is conservative but plausible. We have therefore not revised our CBA further.

The amendment is consistent with regulatory requirements

9.18 The Code amendment attached as Appendix A is consistent with the requirements of section 32(1) of the Electricity Industry Act 2010.

9.19 The amendment is also consistent with the Authority's Code amendment principles: it is lawful and it will improve competition in and the reliability and efficiency of the electricity industry for the long-term benefit of consumers. The Authority has clearly identified an efficiency gain and has used a quantitative cost-benefit analysis to assess long-term net benefits for consumers.

10 Other matters we considered

10.1 The sections to follow give our response to other matters raised in submissions to both our 2017 and 2019 consultation papers.

Whether the scarcity pricing values should be set in the Code

10.2 The quantity and price values for the default scarcity pricing blocks and the risk-violation curves are set in clause 13.58AA of RTP's enabling Code amendment (Appendix A). This is equivalent to current practice for the existing scarcity pricing values today. However, this means the values cannot easily be changed quickly if circumstances warranted it (though the Authority can always amend the Code under urgency). Contact (2019) and Genesis (2017) noted this point. For this reason, Genesis (2017) suggested these values should instead be specified outside the Code.

10.3 We will further consider removing these values from the Code during RTP's build phase, to allow them to be changed more quickly, if necessary. One option may be a similar approach used for the 'customer compensation scheme' provisions in Part 9 of the Code: clause 9.25 requires the Authority to determine and publish the 'minimum weekly amount' under that scheme, with a minimum notice period for any changes.

10.4 Ultimately, where these values should be specified should balance the ability to change them more quickly with:

(a) their importance to the wholesale market's design under RTP, and to spot price outcomes during tight market conditions

(b) starting from a position that the values should not be changed without adequately consulting with stakeholders, and providing sufficient notice for any revisions.

The link to transmission pricing

10.5 Vector stated in its 2017 submission it was:

> surprised the Authority has suggested there is no interdependency between the RTP and its proposed changes for the [transmission pricing methodology (TPM)] in its frequently asked questions on the RTP Consultation.[56]

10.6 Our statement in 2017 was correct: the Authority's TPM proposal did not require RTP being implemented and hence did not depend on it. However, the two projects do have important links. Nodal pricing under RTP will efficiently signal transmission congestion — spot prices will reflect binding transmission constraints, including when such constraints lead to load shedding at individual GXPs.[57] Our TPM proposal will take account of these changes in nodal prices under RTP. Further information will be provided in our forthcoming TPM issues paper.

The accuracy of forecast prices

10.7 Contact, Meridian, and NZS argued in their 2017 submissions that the accuracy of forecast prices in the forward schedules must be improved before implementing RTP. Contact, Genesis, and Meridian also raised the accuracy of forecast prices in their 2019

[56] See the first question on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/real-time-pricing-frequently-asked-questions/.

[57] Because the current scarcity pricing arrangements only apply in the absence of binding transmission constraints, any such load shedding would instead suppress spot prices today.

submissions. Submitters noted the importance of the system operator's load forecast for improving the accuracy of these prices — the MTLF at conforming GXPs (see Box 1 and paragraph 4.205).

10.8 We agree improving forecast prices would help support the efficiency benefits we expect RTP to deliver. We are pursuing improvements to the system operator's MTLF through our *Making price forecasts more accurate* project.[58] We expect this project to be discretionary rather than committed in our 2019/20 work programme. However, we do not consider this work is a pre-requisite to RTP, or that RTP depends on it.

10.9 We also note accurately forecasting prices is likely to become more difficult in an increasingly dynamic power system as consumers take up new technology to better respond to price signals. That response to prices will naturally affect the underlying demand being forecast to produce prices in the forward schedule — demand response to forecast prices is a feedback to the forecast itself. This is an inherent challenge all electricity markets face as consumers increasingly engage with their electricity services. We also commented on these themes in our 2018 decision to update our demand response principles.[59]

10.10 Contact (2017) also cited load control from distributors 'curtailing peak load to reduce transmission costs' affecting forecast prices. It argued forecast prices would be more accurate if this was signalled in advance through bidding. Contact (2019) argued this 'unscheduled demand shedding' will compromise RTP's efficiency benefits. It suggested bidding this load control into dispatch should be made mandatory under the Code.

10.11 We disagree. Our view is that demand response is voluntary, as reflected in the principle of *Choice* in our updated demand response principles. We do not consider forcing distributors to bid their load control into the wholesale market is justified. Distributor load control is currently used for purposes other than responding to wholesale spot prices, including to manage distribution networks themselves (ie, past the GXP level and hence invisible to SPD). Further, our TPM proposal is also likely to change the incentives for distributors to manage peak load in response to transmission prices, moving to better alignment with wholesale spot prices.

10.12 As discussed throughout this paper, we also consider more actionable spot prices — and the potential for nodal scarcity pricing — will encourage participants to engage in demand response. This could lead to retailers contracting to bid distributor load control as dispatchable demand or dispatch-lite, making it more visible in the forward schedules.

The information in schedules

10.13 The Code amendment significantly changes the way information in the schedules (NRS, PRS, RTD) is structured and referenced across Part 13. There are two aspects: inputs used to calculate the schedules; and the contents in them, some of which is published.

10.14 Inputs to the dispatch schedules are now specified in the new clause 13.69B. This incorporates what is currently in clause 13.71, and also clause 7 of Schedule 13.3. All inputs are now specified in the one place. We have also shortened the list by removing unnecessary detail or duplication.

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58 More information is available on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/making-price-forecasts-more-accurate/.

59 See the discussion in pages 15 and 16 of the decision paper, available on our website at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/demand-response/development/demand-response-principles-2018-update/.

10.15 Contact (2019) queried if all inputs in 13.71 are represented elsewhere in the Code, specifically noting revised offers and ramp rates. We confirm they are. Revised offers are covered in clause 13.69B(1)(a). Ramp rates are no longer referenced explicitly, because they are part of the information contained in offers. The exception for agreed ramp rates for intermittent generators is retained explicitly.

10.16 To specify schedule contents, we consolidated all information in all schedules into a new table format (Schedule 13.3B). We removed unnecessary duplication and inconsistencies, and ensured equivalent information is only stated once. We also added new information regarding the number of 'binding risk-setters', to help understand the effects of the risk-violation curves.

10.17 The table in Schedule 13.3B then indicates which information is relevant to each of the three schedule types, and whether it should be published. We also adopted a design principle that all information should be published unless there is a specific reason to withhold it. Only information about particular participants is withheld.

10.18 We consider this addresses NZX's (2017) suggestion that a service provider instead manage the list of published schedule contents, separate to the Code.[60] Publishing all information possible removes the need to manage a list separately.

Preserving existing datasets

10.19 Transpower stated in its 2017 submission it supported retaining all existing datasets currently produced by the pricing manager. It argued this would 'ensure no loss of market information that supports competition and risk management'. Transpower (2019) further noted concern that removing data and information obligations under RTP could have unintended consequences. For instance, removing the obligation for embedded generators to provide injection data to the grid owner could affect load forecasts used in system planning.

10.20 We agree continuing access to necessary information is important for a range of parties. However, we do not agree all current datasets should be preserved without specific justification. There may also be other ways to achieve the same outcome under RTP. For example, injection from embedded generators can be obtained from monthly reconciliation data (rather than maintaining the burden of providing it daily). Though this may require an obligation for the reconciliation manager to provide it to the grid owner.

10.21 We agree with Transpower's (2019) suggestion that we 'should establish what other industry processes are reliant on that data or information' before removing it under RTP. We will use engagement groups during RTP's build phase for this purpose.

Broader discussion in Orion's 2017 submission

10.22 Orion's submission to our 2017 consultation canvassed a range of themes around the scale and pace of change in the electricity sector more broadly. We consider we have addressed the matters relevant to RTP raised by Orion (2017) in our responses above. We consider the broader themes have been or are being addressed by many other projects across our work programme.

60 The earlier form of the Code amendment in our 2017 RTP consultation contained a specific list of information to be published (in Schedule 13.3B), rather than the table approach we have adopted now.

Funding constrained on and off payments

10.23 Constrained on and off payments are funded by purchasers through the clearing and settlement process. In its 2017 submission, Genesis noted this may affect market confidence for spot-exposed purchasers under RTP: they would expect spot prices to reflect their actual spot market costs; yet funding constrained payments is a variable cost beyond spot prices. Genesis (2017) suggested addressing this potential issue by adding a small charge to final spot prices to more transparently reflect the cost of funding constrained payments.

10.24 We consider Genesis' (2017) suggestion may have merit, but we consider this is outside the scope of RTP. However, we have separately been reviewing provisions for constrained on payments.[61] If we decide to pursue further work on constrained payments more broadly, we would consider Genesis' proposal as part of that project.

[61] See our recent *Removing constrained-on payments for generation ramping down* project on our website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/removing-constrained-on-payments-for-generation-ramping-down/.

Appendix A Code amendment

Appendix B Background on co-optimisation and the dispatch process

B.1 This background material is reproduced from section 4 of our 2019 paper.

The system operator schedules additional resources on stand-by to keep the power system secure

B.2 Through the dispatch process, the system operator normally schedules sufficient resources to supply the expected demand for energy on the power system in real-time. However, the system operator also schedules additional resources to quickly respond to any sudden failure of a large generator or transmission circuit. These potential failures are known as ‘contingencies’. The resources used to protect against contingencies are called instantaneous reserve, or simply **reserve**.

B.3 Resources assigned to provide reserve do not supply energy — they are not meeting system demand — but are instead on stand-by, ready to react to any failure. Resources providing reserve are a form of physical insurance, helping keep the power system secure.

B.4 There are two reserve products: fast instantaneous reserve (FIR), and sustained instantaneous reserve (SIR). Both are provided by either generators agreeing to hold back some of their capacity (reducing the amount of energy they can supply at the same time); or by consumers agreeing to automatically cut their demand very quickly if system frequency falls past a certain point, providing ‘interruptible load’ (IL). The amount of reserve required in each trading period is modelled dynamically, varying with the size of the largest generator or transmission circuit ‘risk’ in operation.

Energy and reserve are co-optimised to determine the least-cost use of resources

B.5 The system operator’s scheduling, pricing, and dispatch system (SPD) is tasked with finding a dispatch solution to meet the need for energy and reserve at least total cost. SPD does this by determining the optimal combination of energy and reserve costs, as expressed by supplier offers, dispatchable demand bids, and reserve offers.[62] Through this co-optimisation, SPD schedules (or ‘clears’) adequate quantities of energy and reserve for dispatch in each trading period as the least-cost solution.

B.6 Co-optimisation means SPD may schedule a higher-cost generator offer despite capacity being available from a cheaper supply source. This would occur if the cost of additional reserve to cover increased supply from that cheaper source would result in a greater total cost.

B.7 A range of ‘constraints’ sets mathematical boundaries or requirements SPD should usually honour. Some are hard limits that cannot be broken; eg, generators cannot be scheduled for more than their total offered capacity. Other constraints can be violated if SPD finds the cost of doing so — set by the price of the constraint violation penalty (CVP) — is the least-cost solution. For example, in rare conditions SPD will break the energy deficit constraint at a node or nodes, meaning expected demand for energy

[62] Generators offer to supply specific MW quantities of energy at the price they are willing to accept, while dispatchable demand bids specify the MW quantities purchasers wish to consume, up to a maximum price. Reserve offers are provided by both generators and interruptible loads (ie, there is no ‘reserve bid’).

cannot be fully supplied. The system operator must then instruct emergency load shedding to keep the power system secure.

On rare occasions, reserve is sacrificed to meet the need for energy

B.8 SPD determines the target required MW quantity for reserve in each trading period dynamically (for FIR and SIR).[63] That target is usually the size of the maximum scheduled MW quantity from supply sources — these sources are the **'risk-setters'**. We will call this target maximum scheduled MW quantity the **actual maximum risk**. In turn, the MW quantity of reserve SPD schedules is the **maximum covered risk**. In normal conditions, the maximum covered risk is therefore equal to the actual maximum risk.

B.9 However, resources offered into the market may not be enough to meet the demand for both energy and reserve in real-time during tight market conditions. The long-standing practise in these times of resource scarcity is to partially relax reserve cover, prioritising meeting the demand for energy. Sacrificing reserve in this way frees generation resources from providing reserve to supply energy instead (where generators offer into both energy and reserve markets). If we did not sacrifice reserve, the system operator would have to instruct emergency load shedding to forcibly reduce the real-time demand for energy.

B.10 Sacrificing reserve at these times means there is a shortfall in reserve cover, relative to the target quantity required. The maximum covered risk will be less than the actual maximum risk by the MW size of that shortfall. The power system is therefore temporarily operating at a higher security risk: the reserve shortfall raises the likelihood of triggering widespread automatic under-frequency load shedding (AUFLS) if a contingent event were to occur, but avoids *certain* instructed load shedding now.[64]

Reserve shortfall is driven by SPD as the least-cost solution

B.11 The system operator does not manually decide or otherwise intervene to sacrifice reserve to meet the need for energy. Any reserve shortfall is instead an inherent and automatic outcome of SPD's co-optimisation process. SPD does this because of the relative prices assigned to any violation of the constraints representing a deficit in the scheduled quantities of reserve and energy:

(a) The CVP for a deficit in reserve in either FIR or SIR is set to $100,000/MW/h.

(b) The CVP for a deficit in energy — which would require emergency load shedding — is set much higher at $500,000/MWh.

B.12 These CVP values are far higher than any realistic market bid or offer price. This makes SPD highly likely to use all offered market resources first in meeting the demand for energy and reserve. It also ensures reserve deficit is preferred to energy deficit.

B.13 In times of resource scarcity, SPD is then highly likely to violate the reserve deficit constraint(s) in finding the least-cost dispatch solution. A reserve shortfall would result if physically possible, avoiding emergency load shedding. The real-time price(s) for FIR or

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63 For simplicity this paper does not discuss the role of 'net free reserve' in determining the required FIR quantity.

64 AUFLS is the last line of defence before cascade failure of the power system, if the combination of FIR and SIR were not sufficient to handle a contingency. Load shedding through AUFLS occurs when protection relays automatically trigger at specific system frequencies, without any intervention or control from the system operator. AUFLS is therefore distinct from the *instructed* emergency load shedding discussed elsewhere in this paper.

SIR (or both) would be determined by the $100,000/MW/h CVP, indicating SPD could not find a ‘feasible’ dispatch solution — it had to break a constraint to solve. This situation is then known as a reserve ‘infeasibility’.

B.14 But that outcome is not guaranteed. Under certain conditions, SPD will determine energy deficit (requiring emergency load shedding) is the least-cost dispatch solution, with little or no reserve shortfall beforehand. To reiterate the point above, reserve shortfalls are an outcome of co-optimisation, not an external intervention.

Appendix C Treatment of load and bid types under RTP

A.1 Table 8 lists all load and purchaser bid types, where they apply, and how their price and quantity will be used across the forecast and dispatch schedules under RTP. 'Scarcity' means the relevant load is assigned default scarcity pricing values.

Table 8: Treatment of load and purchaser bids by type under RTP

Bid or load type	GXP type	NRS		PRS		Dispatch	
		Price	***Quantity***	***Price***	***Quantity***	***Price***	***Quantity***
Forecast load	Conforming	Scarcity	Load forecast (MTLF)	Scarcity	Load forecast (MTLF)	Scarcity	Load forecast (STLF)
Non-dispatchable purchasers at conforming GXPs may indicate their intentions, using relative volumes							
Difference bid	Conforming	N/A	N/A[65]	Bid	Bid	N/A	N/A
Non-dispatchable purchasers at non-conforming GXPs must indicate their intentions, using absolute volumes							
Non-DCLS[66] nominated non-dispatch bid	Non-conforming	Scarcity	Bid	Bid	Bid	Scarcity	Persistence forecast
DCLS bidding dispatchable							
Dispatchable demand: nominated **dispatch** bid	Any	Bid	Bid	Bid	Bid	Bid	Bid
Dispatch-lite:[67] nominated **dispatch** bid	Any	Bid	Bid	Bid	Bid	Bid	Bid

65 Difference bids are only indicative in the PRS; their quantity (and hence price) is simply part of the conforming load forecast for the NRS and dispatch.

66 Dispatch-capable load stations (DCLS) refer to the device(s) approved by the system operator for use as dispatchable demand.

67 Dispatch-lite will be a form of DCLS using nominated bids, as for existing dispatchable demand.

Bid or load type	GXP type	NRS		PRS		Dispatch	
		Price	***Quantity***	***Price***	***Quantity***	***Price***	***Quantity***
DCLS bidding non-dispatchable (becomes an indication of intent)							
Dispatchable demand: nominated **non-dispatch** bid	Any	Scarcity	Bid	Bid	Bid	Scarcity	Persistence forecast
Dispatch-lite: nominated **non-dispatch** bid	Any	Scarcity	Bid	Bid	Bid	Scarcity	Persistence forecast

Appendix D Summary of dispatch processes for dispatch-lite participants

D.1 Table 9 summarises the dispatch processes for dispatch-lite set out in section 5 above, in comparison to existing arrangements for generation and dispatchable demand.

Table 9: Summary of dispatch processes for dispatch-lite participants

	Type	Capacity limit	Gate closure	SCADA	Can say no	Constrained on payment	Constrained off payment	Can withdraw from dispatch
Generation	Grid-connected generation	**Must** offer if > 10 MW	1 hour	**Mandatory**	✗	✓	✗	✗
		May offer if ≤ 10 MW		If directed	✗	✓	✗	✗
	Embedded generation	**Must** offer if ≥ 30 MW	30 min	**Mandatory**	✗	✓	✗	✗
		May offer if < 30 MW		If directed	✗	✓	✗	✗
	Distributed generation-lite	< 30 MW	30 min	Not generally required	✓	✗	✗	✓
Demand	Dispatchable demand	No set limit	1 hour	If directed[1]	✗	✓	✓	✓
	Dispatchable demand-lite	No set limit	30 min	Not generally required	✓	✗	✗	✓

Source: Electricity Authority

Notes: 1. By modifying the market system to account for dispatch-lite bids and offers, the need for providing SCADA telemetry when using full dispatchable demand may be reduced.

Appendix E System operator's report on high-spring washer pricing situations

Appendix F Further information on the system operator's PSC tool

F.1 The system operator has provided the following explanation of its post-schedule check (PSC) tool under RTP.

The Post Schedule Check (PSC) tool provides a means of checking cases (schedules) as they solve in order to notify operators and system analysts of abnormal situations. In some cases automatic actions are triggered to prevent automatic case publication or dispatch. In RTP, the current PSC tool provides a means of avoiding situations which may otherwise result in a pricing error.

There are approximately 80 validation rules currently used checking for a range of situations from unexpected changes to schedule inputs to unexpected results from the SPD or SFT calculations. These can be categorised into the following groups:

- Alarms for solution approaching normal operational break points for HVDC operation (eg round power)
- Security checks for the dispatch schedule, such as:
  - Reporting the number of near-binding constraints
  - Generator ramp rate infeasibilities
  - Large changes in load input between dispatch intervals
  - RMT convergence monitoring (ensuring net free reserve quantities do not change significantly from solve to solve)
- Pricing solve checks in the dispatch schedule, such as:
  - Identification of circulating branch flows
  - Flagging high-priced generation clearing
- Similar security and pricing checks for forward schedules

The majority of these validation checks result in the on-call system analyst being notified for follow up either in real time or in next business day, depending on the nature and priority of the check. Other actions that are implemented at the moment are:

- Co-ordinator alarm – triggers co-ordinator action
- Stop Case Approval – If a case is not approved it cannot be dispatched or published without manual intervention
- Dispatch to Manual – If dispatch is in auto-send it switches to manual, requiring co-ordinator intervention
- Trigger CAS solve – if a schedule input change requires a constraint to be adjusted
- Trigger RMT solve – if a schedule input change requires a change to reserve requirements
- Standalone dispatch (SAD) actions – subroutines triggered when MS is offline

Additional PSC validation rules and actions can be included in the market system to facilitate automated price error checking for RTP. We intend to develop additional validation rules and assign appropriate actions as part of the project, but preliminary ideas for additional rules include checking:

- Load shedding / scarcity pricing has resulted from a schedule solve
- Constraint Violation Penalties (CVPs) have been triggered
- Load shedding is required at a GXP where interruptible load is contracted
- Indicating spring washer pricing may have occurred

We anticipate that schedule validation, including post-schedule checking, would be an area for continuous improvement in an effort to minimise system abnormalities causing adverse pricing outcomes. We expect that as part of our internal event investigation process, further checks could be accommodated on an ongoing basis through configuration of new validation rules within the market system. As these additional validation checks would only be implemented to prevent abnormal outcomes, we would not expect to consult on implementation of new checks (but could maintain a public list of checks for participants' reference).

Glossary of abbreviations and terms

API	Application programming interface
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
DCLS	Dispatch-capable load station
DSE	The system operator's Dispatch Service Enhancement project
FIR	Fast instantaneous reserve
FTR	Financial transmission rights
GEN	Grid emergency notice
LCE	Loss and constraint excess
MTLF	Medium-term load forecast at conforming GXPs, used in the forward schedules
NRS	The forward non-response schedule
PRS	The forward price-responsive schedule
PSC	The system operator's post-schedule check validation tool
reserve	Instantaneous reserve, FIR and SIR
RTD	Real-time dispatch schedule, used to produce dispatch prices under RTP
RTP	Real-time pricing in the wholesale spot market
SCADA	Supervisory control and data acquisition
SIR	Sustained instantaneous reserve
SPD	The system operator’s scheduling, pricing, and dispatch system
STLF	Short-term load forecast at conforming GXPs, used for dispatch
WITS	Wholesale Information and Trading System