These answers and the worked example relate to the proposed real-time pricing proposal and were provided to Trustpower in response to questions submitted during the consultation.

Response to Trustpower queries regarding our proposal for real-time pricing

The Authority's responses to Trustpower's queries received by email on 1 September 2017 are set out in the blue boxes and the separate worked example below.

Date: 22/9/2017

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1. Can you provide examples of how RTP would be administered (in particular, at what point real-time scarcity pricing would turn on and then turn off) in the following scenarios (2-5) :
2. Islanding situation at a node or set of nodes in a sub-region, ie, load supplied during a scheduled total Tx outage, by a single offered pivotal generator.

Scarcity pricing only applies to load shedding instructed by the system operator in emergency conditions (a grid emergency notice (GEN) is in effect). It would not apply to outages as such; ie, an outage does not cause scarcity pricing in its own right. Rather, a planned outage effectively constrains available supply or reduces real-time load.

Please see the detailed Worked example below, as well as these written responses.

a. Would the generator have full pricing power (within limits of existing market conduct rules)?

The same rules apply as today; RTP does not change the trading conduct requirements in the Code.

b. If the generator offered at above scarcity price thresholds, would the dispatch solution schedule load off, and therefore limit price to between $10K and $20K ?

Assuming no dispatchable demand bid above $20k (and of sufficient volume), then yes a GEN would be issued and load shedding would be scheduled. If that load shedding is instructed in real-time, the corresponding dispatch price would be set by default scarcity values.

c. If that load was scheduled off, would it actually be shed in real time, and :

The system operator has discretion over whether to dispatch from the schedule where load shedding would occur. It may be possible to temporarily overload assets to avoid load shedding, the same practice as today. If so, scarcity pricing would not apply and the previous dispatch price would continue instead; if not, yes, load shedding would be instructed. However, if any instructions are issued from that schedule—anywhere on the grid, even if the affected assets might have been overloaded—dispatch prices for the affected islanded GXP would be set by default scarcity pricing.

i. If so, would the RTD schedule be immediately adjusted to show demand as reduced according to the real time shedding, and what would be the likely effect on price ?

The quantity of any load shed under a GEN (triggering default scarcity pricing) would be 'remembered' by SPD for as long as that load shedding is needed; ie, while required demand (including the quantity shed) cannot be balanced by offered supply below default scarcity pricing values. So no, the demand required in real-time would not reduce by the quantity not supplied from default scarcity pricing blocks.
Scarcity pricing continues while instructed load shedding is in effect. But of course anyone else can react to those prices by reducing their demand (or increasing supply offers under the GEN). That response could return total required demand—again, including the quantity shed—to the bid/offer stack in the next RTD, ending load shedding and restoring 'normal' prices.

ii. If not, would any other change in demand (eg, due to price response, or to non-offered embedded generation, or both) be measured in real time and a new RTD solve issued immediately ?

Yes, as above: any response to the situation (offered or non-offered) will affect the real-time supply-demand balance in RTD and, if sufficient, return to the bid/offer stack. The dispatch price would be set by the marginal tranche, taking effect when fresh dispatch instructions are issued.

d. If the generator could supply (or chose to offer) only a part – say half - of normal load, would the non-supplied load be scheduled off at scarcity pricing and therefore a price > $10K apply throughout the outage ?

Yes. There is no practical difference to the above scenarios: load cannot be met by available offers below scarcity pricing values. (Again, this assumes no explicit dispatchable demand bids stating a willingness to pay above scarcity pricing values.)

3. <u>Partial islanding situation</u>, ie as above but some Tx capacity still exists but is insufficient to supply all load from outside the sub-region.

Same as above scenarios. The specific physical situation simply affects the supply-demand balance—RTD finds the least-cost optimal solution, incorporating default scarcity pricing values. The key difference is that because some load would be supplied from outside the constrained region, the volume of shortfall would be reduced. That could mean a lower level of scarcity pricing, all other factors being equal; eg, load might now be shed only from the $10k block instead of the $15k block.

4. As for 1 and 2, but transmission outage is <u>unscheduled</u>.

Same as above scenarios. The specific physical situation simply affects the supply-demand balance—RTD finds the least-cost optimal solution, incorporating default scarcity pricing values. Again, the fact of an outage itself does not directly trigger scarcity pricing.

5. As for 1 and 2, but the single pivotal generator is unoffered.

Same as above scenarios. The specific physical situation simply affects the supply-demand balance—RTD finds the least-cost optimal solution, incorporating default scarcity pricing values. We assume this refers to a situation where a load 'pocket' is completely physically disconnected from the grid and there is a pivotal generator that is not offered. We are not sure this is realistic in practice. A pocket of this sort would require separate frequency keeping. It seems unlikely that the marginal generator is not subject to an offer requirement.
Regardless, the absence of any offered generation in this hypothetical scenario means there are only 2 possible outcomes for price: zero or scarcity pricing. Which result occurs is determined by the presence or absence of metered GXP load in the dispatch schedule.

- If there is no metered load at the GXP it would be identified as dead and disconnected. Under RTP we propose a proxy price would then be assigned—currently prices would be set to zero.
- If there is metered load at the GXP, scarcity pricing would apply because there is no way to meet the load with offered generation.

Critically, we note it seems highly unlikely for non-zero load to be observed in this scenario. This requires the electricity injected by unoffered embedded generation to be flowing through the GXP meters to supply the load behind that GXP—an implausible physical situation.

6. Has the EA considered whether a "proxy generator" at scarcity prices, with tranches equal to the 5/15/80% load blocks, would be a superior alternative to virtual load block modelling?

A proxy generator setting the scarcity price would still allow demand to respond to price, but would mean that real time measured demand would be the only input required to the next RTD solve (ie, scheduled load shedding would not be a required input).

This approach would appear to help solve the "circularity" problem, whereby :

a. load that is scheduled off at scarcity prices could be shed off in real time, but would have to be modelled as on in order to avoid a sawtooth effect on price; or (alternatively)
b. load that is scheduled off at scarcity prices actually remains on in real time under SO management, costing consumers/retailers up to $20K/MWh, ie more than their assumed VOLL)

The system operators' detailed market system design will account for these concerns—SPD will 'remember' the quantity of any load shed (see the Worked example below).
On (b): it is unlikely any load instructed to be shed would remain on for more than brief periods—if it did, frequency would begin to fall and potentially trigger a contingent event. In an islanded situation AUFLS may be triggered.

7. Can the EA (or Transpower) undertake a more granular and "progressive" hindcast of RTP pricing ?

It appears that the existing hindcast has not actually reprocessed the RTD solutions that will form the basis of the proposed RTP.

The existing hindcast is aggregated to its high-level effects on TWAP at OTA, BEN and HAY. We would be interested in results at HH level for all nodes, over short term constrained periods in particular.

To that end :

a. Can SPD or vSPD be used to re-run pricing using historical RTD inputs, with the proposed scarcity pricing applied, to show simulated outcomes for all nodes over a longer historical period ?

b. Similarly, can the simulated RTP be run in parallel to existing ex-post pricing solves going forward, so that relative outcomes are visible during the 4 year transition period from ex-post to ex-ante pricing ?

By "in parallel", we suggest this could still be promulgated ex-post for reasons of processing/reporting efficiency, but would nevertheless represent the ex-ante prices intended under RTP.

We believe the above approach could be helpful in identifying some (though not necessarily all) of the unforeseen consequences of RTP in terms of market price risk.

We do not expect RTP to have a material effect in most trading periods, other than making prices available in real-time. For this reason, the historical hindcast analysis provided with the consultation paper[1] concentrated on the subset of trading periods involving 'infeasibilities' or HSWPS situations, etc. A full hindcast should also consider the potential for other factors to change in response to RTP signals—most significantly, bids and offers.

We do not propose undertaking a further hindcast of historic trading periods using vSPD; however, we are considering whether it would be possible to publish notional 'real-time' prices in the lead up to RTP going live. These notional prices would largely simulate the effect on final prices if RTP had been operating—except for behavioural response. Please also see the RTP FAQ: http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/real-time-pricing-frequently-asked-questions/

8. Has the EA modelled the price implications of removing the current spring washer relaxation rule, and

The Authority has recently reviewed HSWPS data for the last 2 ½ years. We identified 20 trading periods where the HSWPS resolution process adjusted prices at one or more North Island nodes (fewer events affected the South Island). We carried out a 'hindcast' simulation by replacing the actual final prices in each affected trading period with the corresponding RTD prices (with an upper limit of $10,000/MWh to represent the lowest default scarcity value). The simulation assumed all HSPWS events affected the same nodes (an unrealistically high case). Our analysis indicated annual average final prices at the affected nodes would have been around $1/MWh higher under RTP.

9. Has the EA considered the benefits of retaining a "times 5" factor on the constrained price during a spring washer situation in real time (ie limiting any GXP price to 5 times the highest unconstrained cleared offer price) ?

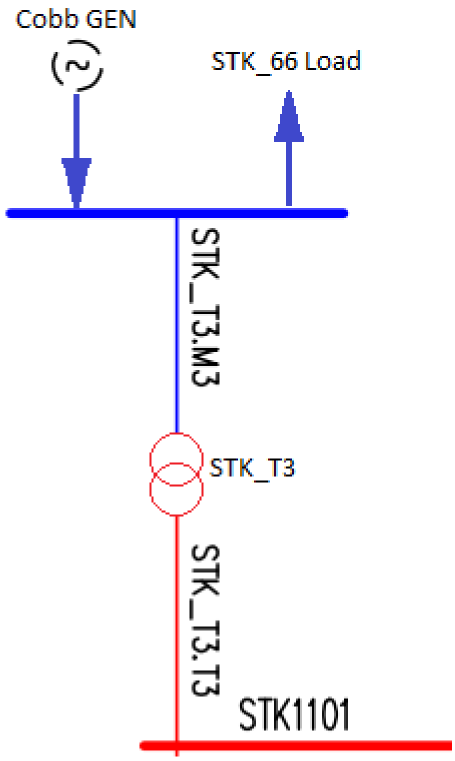
This would not be compatible with real-time pricing. Any post-processing such as this cannot provide a real-time actionable price. It would not guarantee the dispatch price would be less than default scarcity pricing values in any case (eg, 5 x $2100/MWh offer price = $10,500/MWh). Please also see the HSWS question on our RTP FAQ: http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/real-time-pricing-frequently-asked-questions/

[1] http://www.ea.govt.nz/dmsdocument/22390

The Authority’s worked example

The following hypothetical scenarios elaborate on the general questions posed above, illustrating the way RTP is expected to operate. The ‘cases’ refer to the number Trustpower stated in their original questions above.

Consider an islanded situation at GXP STK_T3:



In this situation we can have STK_T3 (transmission asset) and Cobb generation supplying STK_66 load. If STK_T3 is out then Cobb generation can supply STK_66 load.

Trustpower’s case #2 – island formed when STK_T3 is out. Let’s say Trustpower offers Cobb generation in a single tranche quantity 30 MW at a price of $100.

Schedule	Effect
Forecast time (NRS and PRS):	If STK_66 load is forecast less than 30 MW (average for trading period), all load is served, price is forecast at $100. If STK_66 load is forecast more than 30 MW then load is forecast to be shed, price $10k–$20k. This may trigger Trustpower to seek an agreement with Network Tasman to control load to Cobb’s offered quantity.
Real Time (RTD schedules):	Let’s say in the 07:30 trading period, STK_66 load is increasing. It starts at 28 MW and it is expected to go higher. STK_T3 is out and Trustpower is still offering Cobb at 30 MW for $100. No load agreement is in place.

Schedule	Effect
	RTD1 (published 07:29) expects 28 MW of load, all load served, price is $100. RTD2 (published 07:34) expects 31 MW of load. Cobb is at its limit of 30 MW, 1 MW of load shedding is instructed, price is $10k. RTD3 (published 07:39) knows 1 MW has been shed, otherwise expects 29.5 MW. Total expected demand is 30.5 MW. Instructed load shedding of 0.5 MW continues (ie, reduced from 1 MW), price remains $10k. RTD4 (published 07:44) knows 0.5 MW has been shed, otherwise expects 27 MW. Total expected demand is 27.5 MW, which is now fully supplied by Cobb generation, ending load shedding, price is $100. RTDs 5 and 6 published at 07:49 and 07:54 respectively also show no load shedding required, price remains $100. Final price is time-weighted average of the six prices, $3,400. If load were controlled before real-time to a maximum of 30 MW to avoid instructed load shedding, price would be $100.

If for one of the RTDs the expected level of demand was greater than 30 MW, but frequency in the island indicated no imbalance (ie, a discrepancy between modelled RTD inputs and system actuals) the system operator may use discretion and not instruct load shedding.

Supply-demand scenario 1:

- in forecast schedules or RTD schedules conforming load is 30 MW
    - 5% = 1.5 MW, 15% = 4.5 MW, 80% = 24 MW
- Cobb offering two tranches: 25 MW at $100 and 5 MW at $50,000.

Result:

- 5 MW of conforming load (~16.7%) would be shed
    - all 1.5 MW from 5% block + 3.5 MW from 15% block shed
- conforming load supplied to 25 MW
- Cobb generation cleared to 25 MW
- price is $15k.

Supply-demand scenario 2:

- in forecast schedules or RTD schedules conforming load was 25 MW
    - 5% = 1.25 MW, 15% = 3.75 MW, 80% = 20 MW
- there was a DD bid for 2 MW at $25k
- Cobb had the same offers as above

Result:

- 2 MW of conforming load (8%) would be shed
  - all 1.25 MW from 5% block + 0.75 MW from 15% block shed
- conforming load supplied to 23 MW, all 2 MW DD load dispatched on, total load 25 MW
- Cobb generation cleared to 25 MW
- price is $15k.

Supply-demand scenario 3:

- in forecast schedules or RTD schedules conforming load was 25 MW
  - 5% = 1.25 MW, 15% = 3.75 MW, 80% = 20 MW
- there was a DD bid for 2 MW at $100k
- Cobb had the same offers as above

Result: Same result as scenario 2—the DD bid now priced above the $50k Cobb tranche does not change the dispatch outcome.

- 2 MW of conforming load (8%) would be shed
  - all 1.25 MW from 5% block + 0.75 MW from 15% block shed
- conforming load supplied to 23 MW, all 2 MW DD load dispatched on, total load 25 MW
- Cobb generation cleared to 25 MW
- price is $15k.

The only way we 'get past' default scarcity pricing blocks to clear the $50k Cobb tranche is if the DD bid quantity is greater than the quantity offered for the $100 Cobb tranche. If so, both Cobb tranches would be needed to supply the DD bid quantity. This is illustrated in scenario 4.

Supply-demand scenario 4:

- in forecast schedules or RTD schedules conforming load was 5 MW
  - 5% = 0.25 MW, 15% = 0.75 MW, 80% = 4 MW
- there was a DD bid for 26 MW at $100k
- Cobb had the same offers as above

Result:

- all 5 MW conforming load would be shed
- all 26 MW of DD load is supplied
- Cobb generation cleared to 26 MW (including 1 MW at $50k)
- price is $50k.

Trustpower's case #3 – 'partial island' is the case where STK_T3 is in service but its rating is insufficient to meet the required load, so Cobb must be dispatched on. In this example let's say grid electricity coming through STK_T3 is $50, and T3 can supply 20 MW.

The forecast situation price will be $100 for forecast load less than 50 MW, $10k or above for more.

In real time, price will be $100 for each RTD where load is less than the offered capability of Cobb and STK_T3 (total 50 MW). If the load is expected to increase beyond 50 MW, load shedding is instructed and price goes to $10k or above.