Supplementary Information for Scarcity Pricing Consultation

Response to request for further information #1

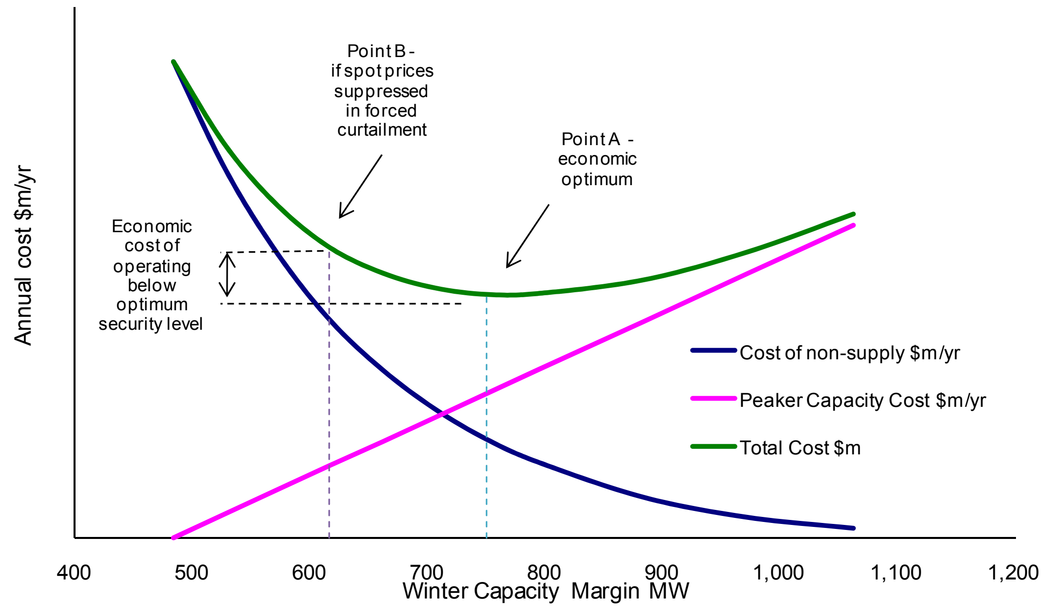
Responses to question re cost benefit estimates

Q1. How have the benefits been quantified (presumably in terms of a number of avoided curtailment events, valued at the estimated cost of curtailment)? It would be useful to know the key parameters used to calculate this value.

The estimated benefit in the basecase is $12m per annum. This figure represents the estimated *change in total system cost* (being the combined sum of generation costs and non-supply costs).

In graphical terms, the change in system cost is represented by the movement along the green line in Figure 43 of the Consultation Paper (reproduced below).

Figure 43 Trade-off between cost of non-supply and cost of supply - illustrative



The cost of non-supply function was estimated using the same approach as that used in 2008 by the Electricity Commission to calculate an optimal capacity margin.

In essence, the methodology uses a Monte Carlo simulation technique to estimate the frequency and magnitudes of capacity shortfalls (i.e. voluntary restraint, IR shortfalls, or load shedding) that would be expected for differing capacity margins. This information is combined with shortage cost estimates to derive the 'cost of non-supply' function. This function is expected to be non-linear as shortfall costs rise disproportionally with more frequent/severe events.

The framework used by the Electricity Commission in 2008 was updated to reflect the expected position once Pole 3 of HVDC becomes available in 2013, and incorporated slightly higher shortage cost assumptions to reflect inflation as per below.

Tranche	Nature of response	Assumed cost $/MWh
1	Lower cost demand response	$1,167
2	Risk of AUFLS with 100MW IR shortfall	$2,335
3	Risk of AUFLS with 200MW IR shortfall	$4,669
4	Risk of AUFLS with 300-400MW IR shortfall	$11,673
5	Load shedding	$23,347

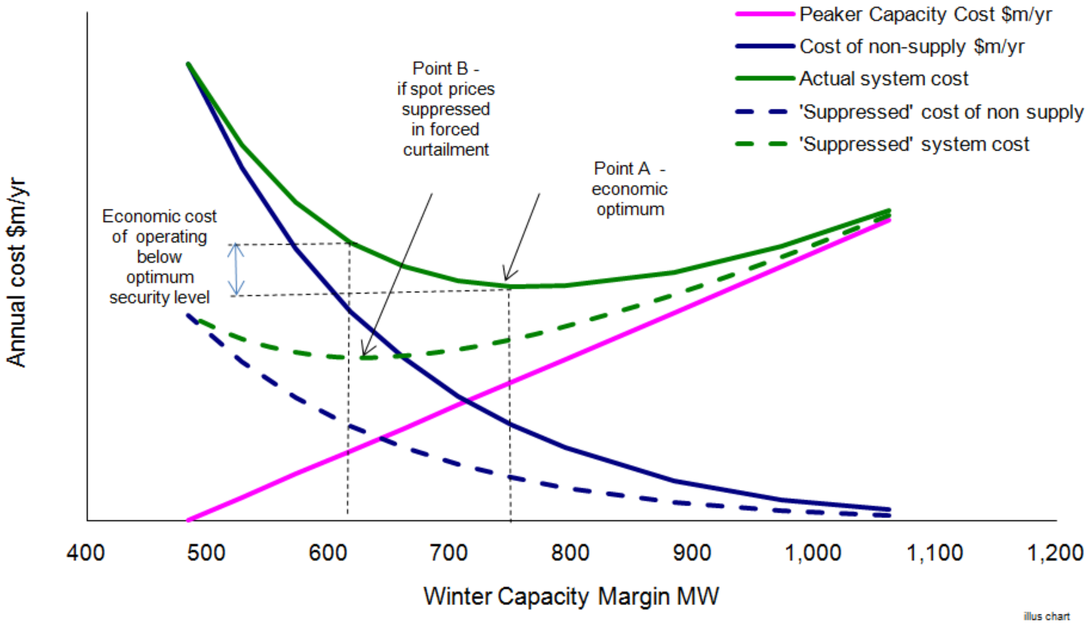
Further detail on the underlying simulation technique is available in http://www.ea.govt.nz/document/2230/download/industry/ec-archive/security-of-supply/security-of-supply-policies-archive/.

The 'cost of supply' function was based on an open cycle gas turbine as the marginal supplier, with variable operating cost of $350/MWh and standing cost of $145/kW/year. This function is expected to be linear[1] with the system margin.

The supply and non-supply information was combined to define the total system cost curve.

The last step in the process was to estimate the difference in total system costs between the basecase (with spot price suppression) and the scarcity price case (without price suppression). In graphical terms, this is difference in system costs between point A and point B in Figure 44 of the paper (reproduced below).

Figure44 Estimating effect of price suppression on security margin - illustrative



[1] For ease, the variable cost of fuel was subtracted from the shortfall costs in the table above for the purpose of estimating the net system costs. This does not affect the results but simplifies the graphical representation.

The position for point A was estimated by identifying the capacity margin with the minimum system cost level.

The position for point B was estimated by considering the effect of price suppression under existing arrangements. Spot price suppression reduces the cost of non-supply that is *perceived* by market participants. As a result, the apparent optimal capacity margin will be lower. As discussed in the Consultation Paper, two different 'non-scarcity price' counter-factual cases were considered, with different levels of spot price suppression.

These yielded estimates of $3 million and $12 million per year for net system benefits from scarcity pricing, depending on which counter-factual was used as a baseline.

Hopefully this helps to explain the derivation of the net benefit figures. More detail can be provided if needed, and it may be easiest to do this via a teleconference.

Q2. Have any costs relating to more conservative fuel management been included? For example, one would expect the scarcity pricing regime to lead hydro generators to manage hydro levels more conservatively. In some cases, this will lead to more spill. Some of the generation lost through spilling this water will need to be replaced by other generation sources.

It is correct that scarcity pricing is expected to make wholesale participants more conservative with *operating* and/or *investment* decisions.

If investment is fixed, participants would only be able to alter their operating decisions, and this would be likely to lead to increased hydro spill (among other things). However, investment is not fixed (only than in the near term) and some investment response would be expected.

The situation is analogous to demand growth. If there was a sudden and permanent lift in demand, this would be expected to increase expected hydro spill and thermal burn (assuming no change in security) in the short term. However, permanently higher demand would be expected to stimulate new investment. Once this was on line, the hydro spill and thermal burn would be expected to return to longer term average levels.

The cost benefit analysis focussed on the longer term effects and assumes that participants have sufficient time to alter investment plans due to phase-in provisions for scarcity pricing. For this reason, it does not factor in any shorter term effects from changes in operating decisions.

For completeness, it should also be noted that the cost benefit analysis in the consultation paper focussed mainly on *capacity* adequacy, since this appears likely to be the more binding constraint. Hydro spill is more likely to be an issue in the context of scarcity pricing for *energy* shortfalls. However, provided sufficient lead time is given, participants should be able to adjust investment plans if necessary.

Q3. Have any costs been included to account for bringing forward investment in generation plant? The price signals resulting from scarcity pricing are intended to incentivise investment in peaking generation, resulting in some investment being made earlier than under the counter-factual.

Yes – the approach adopted does include the extra costs associated with more investment in supply-side resources, and running of those resources at times (i.e. fuel and other variable costs).