Supplementary Information for Scarcity Pricing Consultation

Response to request for further information #2

Supplementary Information on Cost Benefit Analysis for Scarcity Pricing

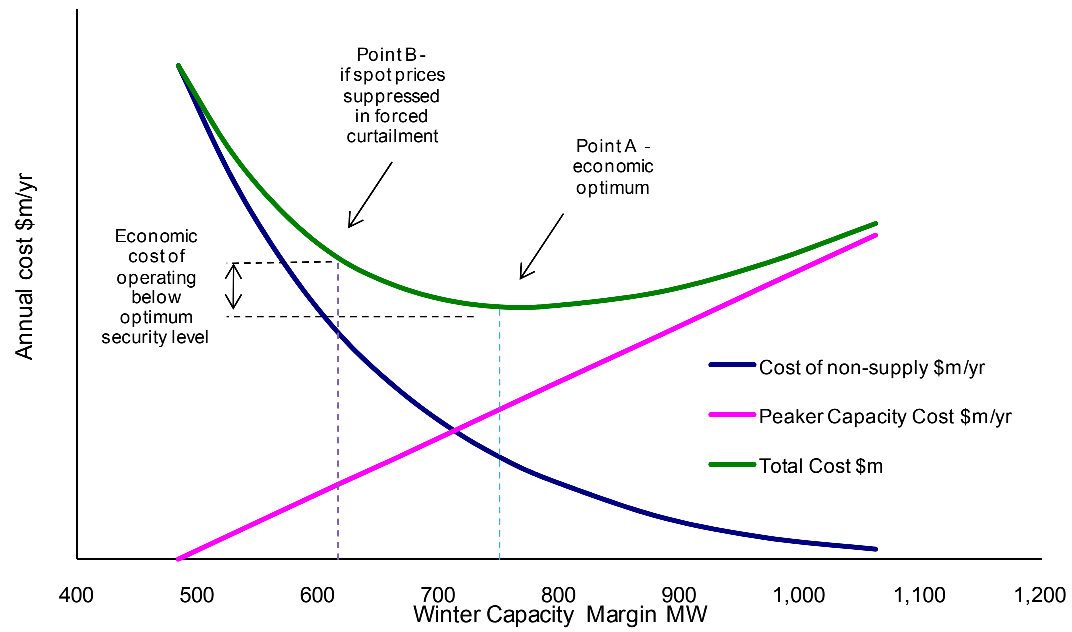
A number of questions were raised about the cost benefit analysis for scarcity pricing at the workshop on 19 April. This note provides further information to address those questions.

Q1. How have the benefits been estimated?

The benefits represent the estimated *change in total system cost* (being the combined sum of generation costs and non-supply costs), for scenarios with and without scarcity pricing.

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. 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 200-400MW IR shortfall	$11,673
5	Load shedding	$23,347

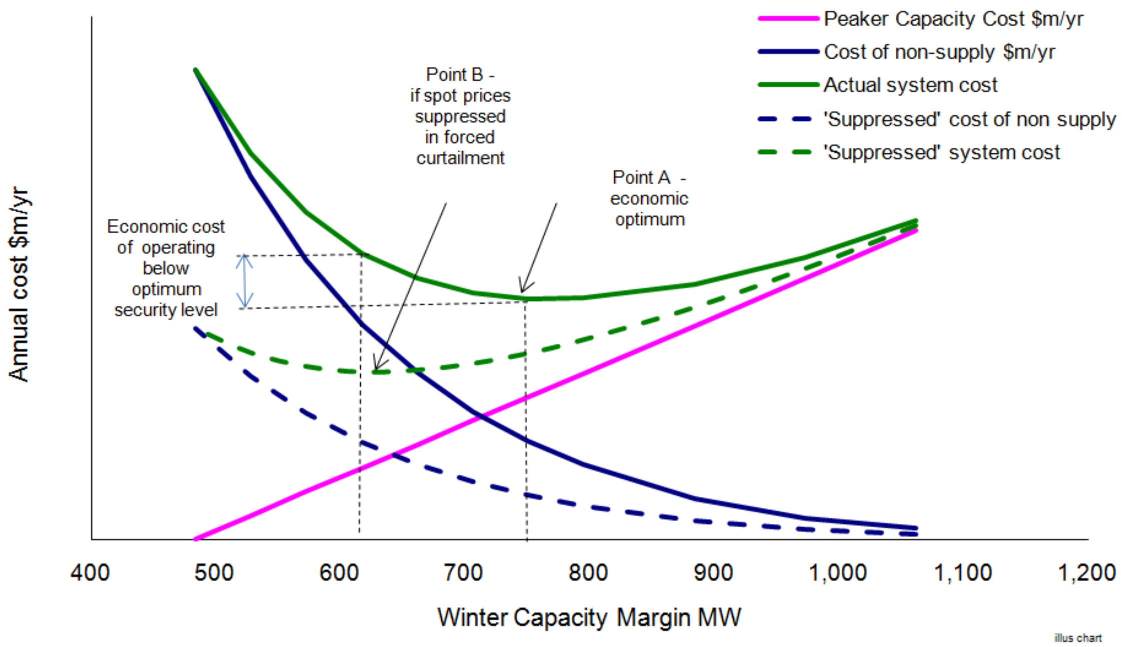
Further detail on the underlying simulation technique is available in http://www.ea.govt.nz/document/2230/download/industry/ec-archive/security-of-supply/security-of-supply-policies-archive/.

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).

Figure 44 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.

Q2. What is the assumed number of hours of load shedding, IR shortfall etc for the differing scenarios?

The estimated number of average hours for different 'shortage states' arising from capacity shortfalls (in steady state equilibrium) is set out below:

Hours (marginal per year on average)	Proposal	Status Quo	Alternative Status Quo
Risk of AUFLS with 100MW shortfall	10.8	22.3	15.4
Risk of AUFLS with100- 200MW shortfall	5.5	11.5	7.9
Risk of AUFLS with 200-400MW shortfall	4.9	11.4	7.5
Instructed load shedding (ex AUFLS shedding)	1.9	5.0	3.1

Q3. Why is the system assumed to have a margin below the optimum in the basecase (absent scarcity pricing), but the most recent Security Assessment by the System Operator indicated a capacity margin above this level.

As discussed in the Consultation Paper, the cost benefit analysis has been modelled over a period of 30 years. The annual benefit estimates therefore reflect the position that would be expected once the system has reached a steady state.

As stated in the Consultation Paper, "In practice, benefits are unlikely to accrue immediately, and some phase-in should be allowed. For this reason, a range of scenarios have been considered where benefits of scarcity pricing are progressively realised over two, three, or five years".

While the phase-in assumptions were not explicitly tied to the recent System Operator Annual Security Assessment (ASA), they do not appear to be incompatible. For example, in relation to winter capacity margins, the ASA stated:

- "capacity margins are projected to be above the Winter Capacity Margin [780MW] in 2011 and 2012 in all scenarios;
  - without the addition of further generation in 2013, a high demand sceanrio or the loss of Whirinaki could see capacity marins fall below the Winter Capacity Margin [sic]."

It is also important to note that the ASA projections are subject to uncertainties. In particular, the projected margin will be quite sensitive to any change in the assumed availability of large thermal units.

Q4. How has voluntary demand response been accounted for in the CBA?

The Monte Carlo simulation technique noted above uses historic demand data as one of its inputs. This data includes the effect of observed voluntary demand response when the system becomes tight. For this reason, the analysis does allow for observed voluntary demand response.

Also, consistent with the approach used in the 2008 capacity standard work, a further 10 MW of real-time market demand response (in addition to interruptible load) was included in the Monte Carlo simulation.

It is possible (in fact desirable) that the level of voluntary demand response capability will increase further over time. However, it appears unlikely that this would fundamentally alter the results of the analysis.

For example, if (say) 200 MW of additional voluntary demand response became available at $500/MWh and nothing else changed, this would affect the *aggregate* amount of generation required on the system at the optimum standard. However, it is unlikely to materially affect the optimum *capacity margin* (which can be provided by generation or firm demand response such as interruptible load).