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Submissions
Electricity Authority
P O Box 10041
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By email: submissions@ea.govt.nz

Dear Tim,

RE: Consultation Paper – real-time pricing proposal

The Independent Electricity Generators Association Incorporated (IEGA) welcomes the opportunity to make this submission on real-time pricing (RTP) proposal published by the Electricity Authority (Authority) on 1 August 2017.

The IEGA comprises about 40 members who are either directly or indirectly associated with predominantly small scale power schemes connected to local networks throughout New Zealand for the purpose of commercial electricity production.[1]

All but one of our members does not currently dispatch their generation in the spot market. Given the capacity of individual plant this is consistent with the requirements in the Code. The threshold in the Code was put in place to acknowledge the additional compliance and overhead costs of dispatch in the spot market. The threshold continues to be relevant as our members do not have the physical (or financial) resources to manage a 24/7 'trading' activity. We are price takers and have historically responded primarily to transmission and network peak pricing signals through the Part 6.4 payment mechanisms. Changes to Part 6.4 and future changes to the TPM mean our membership may be interested in dispatch if there is clearly value from participating.

The IEGA understands the benefits of clearing the spot price in real time and having actionable prices in the spot market. However, we seek more clarity about the RTP proposal in relation to distributed generation (DG) and how DG can 'participate' or receive revenue under the proposal.

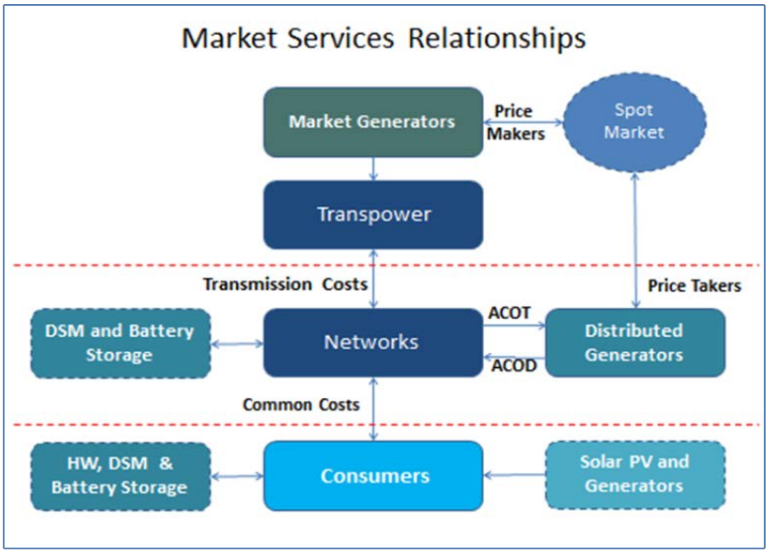
We have outlined our concerns and questions by responding to some of the questions asked in the Consultation Paper – see below.

[1] The Committee has signed off this submission on behalf of members.

Q1. Do you agree with the broad principle of using dispatch prices to determine final prices?

The IEGA agrees that dispatch prices should, where possible, determine final prices. However, it remains unclear how final prices will be discovered as it appears the dispatch process for DG (and similar energy storage devices[2]) has not been specifically considered in the proposed design.

As illustrated in the diagram below DG owners sit in a unique position relative to other participants.



The RTP proposal includes specific provisions for consumers at ICP meters and for directly connected consumers to bid into the spot market using either the Demand Dispatch or Dispatch-lite mechanisms.

A correctly designed market should ensure transparency, information symmetry and price discovery for all participants. The proposal is unclear as to how DG owners can actually participate in the proposed RTP spot market.

This is important as Transpower[3] estimated DG supplies about 8% of peak demand. Demand response was estimated to reduce peak demand by the about the same amount. This total 'response' to peak transmission and spot pricing respectively is about the same as the scarcity price blocks for forecast demand proposed in the Consultation Paper[4] - at 5% and 15% of demand.

The IEGA has the following concerns:

DG is currently included on the Demand-side

The System Operator currently creates a net demand forecast at each GXP. This assumes both DG and demand response (DR) volumes are netted off demand based on historic practices.

Under the RTP process, load forecasts must be based on gross GXP demand forecasts. Both DG and DR supply resources, such as batteries, should have the option of being able to participate in the price discovery process – if they want to. This would require a more fundamental change in the RTP price setting process than currently contemplated – i.e. more a bottom up than a top down process. This

[2] However, we note that the recent Q&A responses indicate battery use is being contemplated for dispatch and price setting

[3] Transpower's TPM Submission July 2016, Appendix G by Scientia Consulting at http://www.ea.govt.nz/dmsdocument/21133

[4] Table 1, page 19 of Consultation Paper

would also be more accommodating of rapidly changing technologies and potential new services. It is not appropriate to just ignore or overlook DG volumes in the design.

Is DG to be on the Generation side of spot market?

DG has historically delivered up to 11% of total electricity supply. We believe DG would make a material contribution to price discovery and suggest the system be designed so that DG can:

- be allocated to the supply side of the market as a generation bid; and
- bid as Dispatch-Lite (ie. the same arrangement as for load); and
- for non-conforming DG, be allocated scarcity pricing (consistent with load that is non-conforming).

Investment signals from nodal prices

The recent decision by the Authority to remove ACOT payments to DG that does not contribute to grid reliability has eliminated the incentive for DG to respond to peak demand. Further, the Authority opined that DG would respond instead to nodal spot prices to ensure the highest possible revenue.

The overall intention of the RTP appears to be to achieve a reduction in average spot prices through demand-side bidding. The following extract highlights this focus:

> 4.21 This analysis indicates that if improved demand response is the sole benefit of RTP, it would need to increase by approximately 10 MW to breakeven under the base case cost estimates. This level of improvement in demand response appears relatively modest in overall terms, as it represents slightly more than 0.1% of total system demand in peak periods.

The design of RTP seems to be highly influenced by improving short run marginal cost efficiencies.

Clearer options for DG and DR to participate are needed to adequately incentivise or compensate for being involved in dispatch (these options combine at more than 20% of peak capacity). Otherwise the price discovery and investment signals would appear to be severely compromised.

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages?

Yes, we agree with the use of default scarcity prices to handle generation shortages.

However, it is unclear what the default scarcity volumes might be. The proposal suggests all non-dispatched demand be allocated a scarcity price. We query whether this includes all network controlled demand, Transpower's Demand Response programme volumes and all DG?

We refer again to Transpower's analysis[5]. The following extract shows peak price responses from Embedded Generation (EG) and Demand Response (DR) are reasonably consistent across each transmission region. This, therefore, reasonably represents the average price response from the demand side.

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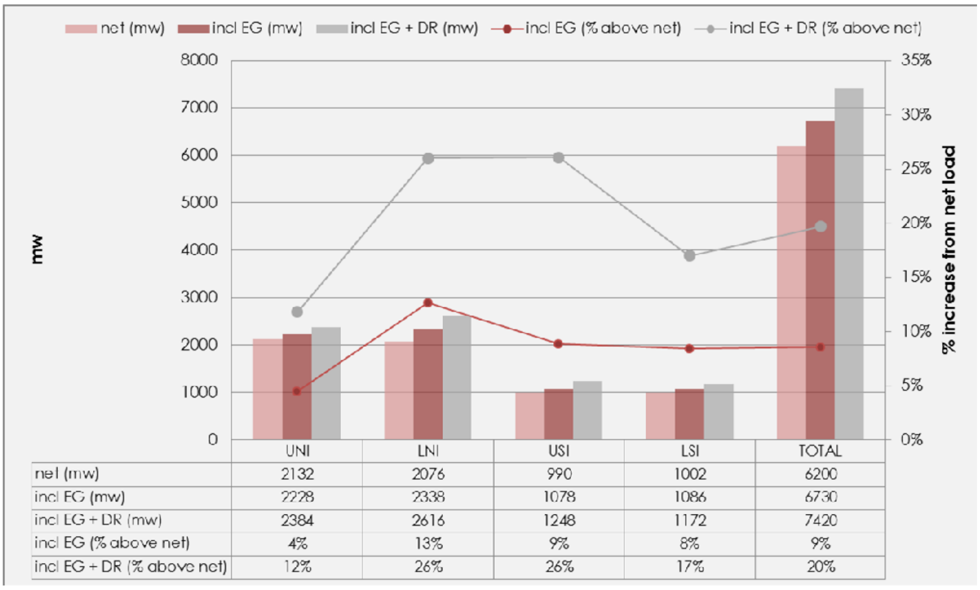
[5] Transpower's TPM Submission July 2016, Appendix G by Scientia Consulting at http://www.ea.govt.nz/dmsdocument/21133



	UNI	LNI	USI	LSI	TOTAL
net (mw)	2132	2076	990	1002	6200
incl EG (mw)	2228	2338	1078	1086	6730
incl EG + DR (mw)	2384	2616	1248	1172	7420
incl EG (% above net)	4%	13%	9%	8%	9%
incl EG + DR (% above net)	12%	26%	26%	17%	20%

Source: Transpower TPM Submission – July 2016 – Appendix G

How is network controlled DR going to be defined in the bid stack?

We also note that Transpower is developing an ICP based demand response platform. It is reasonable to expect that demand side responses managed by Transpower will increase over time.

Is all of this capacity, being for the most part not dispatched, going to be bid at scarcity prices?

As discussed above, our view is that the EG/DG component of this capacity, if not dispatched, should then be allocated on the supply side, at the same scarcity prices. This would result in approximately 8 to 10% of supply and demand being allocated scarcity prices on each side of the market.

Has this outcome been contemplated in preparing this proposal? If this outcome was considered what were the arguments for and against in developing the proposal?

Q5. Do you agree with using the default scarcity bids before generation or dispatchable demand offered at a higher price in the dispatch schedule?

In principle no, we do not agree with using scarcity bids before generation.

The Authority has advised in numerous other rule changes or proposals[6] that nodal spot pricing is the most efficient mechanism for incentivising new generation investment and co-optimisation of generation and transmission investments. For example, the prior ACOT capacity pricing regime was put in regulations in 2007 to ensure that DG would likely dispatch at the most efficient time – that is, during periods of peak demand. The Authority has removed this mechanism as being inefficient and a subsidy. That is, the Authority is seeking to have a 100% reliance on spot nodal price signals for new investments.

[6] For example, the December 2016 decision to change Part 6.4 of the Code; TPM Second Issues Paper

The use of default scarcity pricing load bids ahead of generation (for ~20% of the load) effectively removes or dampens the nodal price signals for new local generation investments, for battery storage and for market priced demand response.

The Authority must now allow the nodal price to be freely determined by the market without constraints. Artificial price caps for different classes of dispatch will result in the nodal investment signals are lost.

As noted for Q1 above, our view is that DG bids and volumes must be allocated to the supply side to ensure adequate price discovery and a level playing field between all generation market participants. Dispatching scarcity ahead of generation bids applies a notional price cap in the spot market for all DG price takers behind the GXP.

Q6. Do you agree the system operator does not need to make changes to the existing process it uses to notify distributors of emergency load shedding?

In our view, the assumptions underpinning the proposed dispatch process rely on historic practices. Both DG and DR have historically been dispatched in response to strong RCPD and ACOT price signals. With the loss of ACOT payments, DG and DR will be incentivised to aggregate and dispatch into the most favourable market/s.

We therefore believe there will be a co-dependency between whether DG can be bid on the supply side of the spot market, as we propose above, or otherwise end up captured by the processes for dispatch of emergency load shedding. For example, if all DG is:

- allocated scarcity prices and is on the supply side of the spot market, then how is this capacity dispatched to ensure no emergency load shedding?

- aggregated with DR on the demand side of the spot market, and DG cannot receive constrained-on payments as it is non-conforming, this capacity has no mechanism to be dispatched ahead of emergency load shedding.

We suggest the market price should be set by generator offers before any emergency load shedding is undertaken. We would like the Authority to first address the matters discussed in relation to Q1 to Q5 before making decisions on the emergency load shedding procedures.

Summary of our main points:

1. DG owners with plant capacity under 30MW have effectively been excluded from the RTP design process.

2. DG needs a mechanism like Dispatch-Lite and to be able to bid volumes on the supply side to ensure equal market participation.

3. DG should not be included in the net GXP demand forecast as it is a competitive and discretionary bid option. Demand forecasts should be at gross GXP demand (excluding DG and DR).

4. DG and DR not dispatched should be allocated scarcity prices on opposite sides of the market. This then ensures transparency and information symmetry for price discovery.

5. The nodal price signals need to be considered for short run RTP efficiencies and long run new generation investments. Adding artificial price caps for network load shedding to nodal pricing is inconsistent with the Authority’s views in the DGPP decision that nodal pricing should be relied on to signal peak demand and capacity constraints.

We would welcome the opportunity to discuss this submission with you.

Yours sincerely

Warren McNabb
Chair