Evolving market resource co-ordination: Tie-breaker provisions

Consultation Questions

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Organisation:	PBA Consulting

Question 1: Do you support our proposed tie-breaker solution: dispatch in proportion to offers? Do you have any feedback on any aspect of it or our consideration of it?

The 'Dispatch in proportion to offers' proposed solution is shown to function in other systems, yet there are a number of aspects where it is likely not to suit the needs of the New Zealand system, and as such as presented this is **NOT SUPPORTED**.

The most likely pitfall is that a dominant generator on a GXP could bid in 48 hours prior with their full 100% output, where realistically we are all aware weather conditions dictate solar and wind output. There is presently no provision to prevent this. With the market operation as existing this then allows a later refinement, where they are aware they already have priority at that GXP.

As an example a GXP with a load limit of 130MW, has 100MW geothermal, 50MW Wind A, 20MW Wind B, and 40MW Solar connected, then 80MW geothermal is bid in, plus Wind A at 50MW, while the 20MW Wind B and 40MW Solar are excluded. At that half hour the 80MW geothermal operates, yet only 20MW of Wind A is available, leaving a 30MW shortfall up to Wind B and Solar. This means every half hour the other generators are left in a mad scramble to make up that varying shortfall. Dispatch on a pro-rata basis will leave the market with constant uncertainty, which lessens the chance of generation investment.

It is certainly essential to evaluate the models used overseas, yet alternatives need to be assessed, and investigate how these function with a similar high proportion of renewables, potentially similar to the New Zealand generation mix. This will be challenging as no country has a high geothermal and hydro base load, with wind and solar as exists on the Transpower grid. The Canadian system (60% hydro, 12% gas, 15% nuclear, coal 5%, renewables 8%) has some similarities, with a nuclear and hydro baseload, yet does not have the significant wind and solar of NZ, and as detailed in the discussion document has a complex 'timestamp, equal share, and pro-rata allocation' system.

A purely **technically based allocation system** could benefit all, by known technical capabilities that can be enhanced to the benefit of all, by the generator at their site and for connection to the GXP. Thus an example model may need to be run, of a hybrid system, customised to New Zealand conditions, to determine the appropriately weighted technical criteria.

This is described in Question 2.

Question 2: If you do not support our proposed tie-breaker solution, which alternative option would you prefer? If so, please describe the alternative and why you prefer it.

Solution '4.5 Prioritising different types of generation – **Option Item 51', is supported**, as Transpower will retain the ability to dispatch generation that provides the most stable and secure means to supply and support the grid. By establishing a ranking system at each GXP, or line connection, this gives market predictability, on which generator business models can be based.

For this reason Option 53. is **NOT** supported as it gives no assurance to Transpower that the 'negative price offers' will not destabilise the wider system, by financial gains to generators prioritised over system reliability.

With Option 51. to overcome the issues raised in Option 52. A ranking system would need to be developed, based on technical capabilities of respective generation types, including forms of 'spinning reserve' capability, variability of output (and hence reliability minute-by-minute). These factors are often challenging to quantify with renewables like solar and wind, yet for base load geothermal this would generally rank highest.

To give a scenario that illustrates a functioning Option 51. System, if there was a GXP constraint of 100MW, with 80MW (of 100MW) geothermal, 35MW (of 50MW) 'Wind A', 15MW (of 20MW) 'Wind B', and 20MW (of 40MW) Solar, all bid in at $0/MW, the following ranking would apply, as a suggestion.

80MW geothermal, as this is secure and reliable base load output, with a negligible variation, plus ability to ramp up to 100MW if required at very little notice, useful for frequency and voltage support.

20MW 'Wind A', as this can take into account momentary loss of wind energy more capably than the 20MW peak output of Wind B, or Solar, as long as there is a sufficient wind forecast.

If the weather forecast however was for negligible wind, yet high solar, this would elevate **20MW** Solar during the daylight period.

Where this appears to knock out 'Wind B' and Solar in most scenarios, there may be an option to add 'market diversity' as a means of increasing security. Each of the renewables would have differing means of connection, up to the GXP, and 'security of supply' needs to take this into account. Should Wind A have a 50km single 33kV line connection, while Wind B has a dual 33kV 5km connection, this could raise Wind B up the ranking. Taking this into account the end result for the 100MW output may look like;

80MW geothermal, **15MW** Wind A, plus **5MW** Wind B (ready to ramp up to 20MW if the single Wind A line is lost)

Alternative Tie-Break '3 Criteria Ranking System'

As a variation on Option Item 51. a ranking system would therefore need to be technically robust to avoid legal challenges that it favours certain generators unfairly, and as such will require detailed modelling and analysis, with comprehensive technically driven dispatch criteria. Generally there would be three technical dispatch criteria to be employed ;

1. **System Support :** Ability to ramp up to counter loss of another generator on the GXP, or on the wider system, to provide voltage support and frequency support, which generally favours rotating generation, would achieve a higher dispatch ranking. This avoids the situation

experienced in Spain and Portugal on 28th April 2025, where lack of rotating plant for voltage and frequency support, and over-reliance on renewables which could not support voltage or frequency, resulting in a regional grid failure. [*Lombardi, Pierto (18 June 2025). "Spain's grid operator blames power plants for blackout, disputes miscalculation". Reuters. Retrieved 23 June 2025*] Thus a preference for higher dispatch ranking rotating plant enhances grid security.

2. **Weather Variation Durability** : A focus on more conservative weather influenced offers, when wind and solar varies minute by minute, will encourage developers to look toward the most reliable all-weather generation, to ensure a higher dispatch ranking.

3. **Security of Supply Risk / Connection to GXP :** This takes into account technical equipment based criteria, including line diversity, line route length and terrain, plus equipment condition. Hence indoor switchgear, short line and duplicate line connections, would rank higher, enticing asset owners to consider increased connection investment to gain a stronger dispatch ranking, and thus greater return on investment, which is a logically natural outcome.

Thus dispatch would have an additional factor, beyond the present $/MWh bid into the market, which will be relevant when tie-break situations occur. Criteria 1. and 3. will be fixed for each generation asset, with Criteria 2. varying only for weather dependant generation.

Criteria 3. when made clear to all existing and potential generation owners will highlight those parties can elevate their ranking by either building their connections to a higher standard, or by enhancing an existing connection, at their cost or by negotiation with the network or Transpower. This avoids the next issue that inevitably needs to be addressed, being that Transpower assets outside the GXP could be a constraining factor. The tie-break situation can be used as a means to have existing Transpower asset load constraints dealt with by generator investment contributions.

Question 3: Are there alternative options we have not identified which we should consider?

While both the electricity and gas markets are at present considered independent, with gas transition to electricity placing an ever increasing burden on the Transpower transmission and network distribution systems, it is beneficial to consider the option to combine both. This may initially sound bizarre. Yet hydrogen technology allows energy transfer from 'electricity to hydrogen gas' by electrolysers, and 'hydrogen gas to electricity' by fuel cells or hydrogen fired rotating generators. Electrolysers and fuel cells are operating across the country at present, each independent, while linking the electricity and gas systems creates a vastly more capable, and renewable, energy system.

The Natural Gas pipeline in the North Island, unlike the electricity network, does not require an instantaneous generation to load match. The gas network, supplying around 3 x the energy of the electricity network, has an inherent buffer of some hours to days. Some industrial processes are vastly more effective operating from gas for heating purposes.

A partial solution to the tie-break situation would be either full or partial electrical output from renewables to be utilised for hydrogen production. This can then be coupled with hydrogen use for rotating generation. Ultimately the Huntly site could be equipped with over 2,000MW of hydrogen gas fired turbines, providing secure renewable output, including valuable voltage and frequency support.

To give an example, if there is a 100MW solar farm established at a 50MW capable Transpower GXP, solar varies from 0-100MW through the day, and may bid in at $0/MWh for 50MW for 11am to 3pm. Solar energy up to 11am is clearly a lost opportunity for the generation owner, as is output over 50MW for 11am to 3pm, and any output after 3pm. Financial viability is based purely on electricity output. However potential revenue is significantly boosted if the additional output is considered. In this case a series of hydrogen electrolysers at the solar site, which can vary H_2 output to match electrical supply, would produce a secondary revenue source, plus inject H_2 into the Natural Gas pipeline up to 20% with no appreciable technical impact, while hydrogen itself is 34kWh/kg and Natural Gas 15kWh/kg. Ultimately the Natural Gas pipeline can be converted to hydrogen, as is the case in a number of transitions across Europe.

This gives renewable solar and wind (potentially geothermal and hydro) operators 3 revenue options;

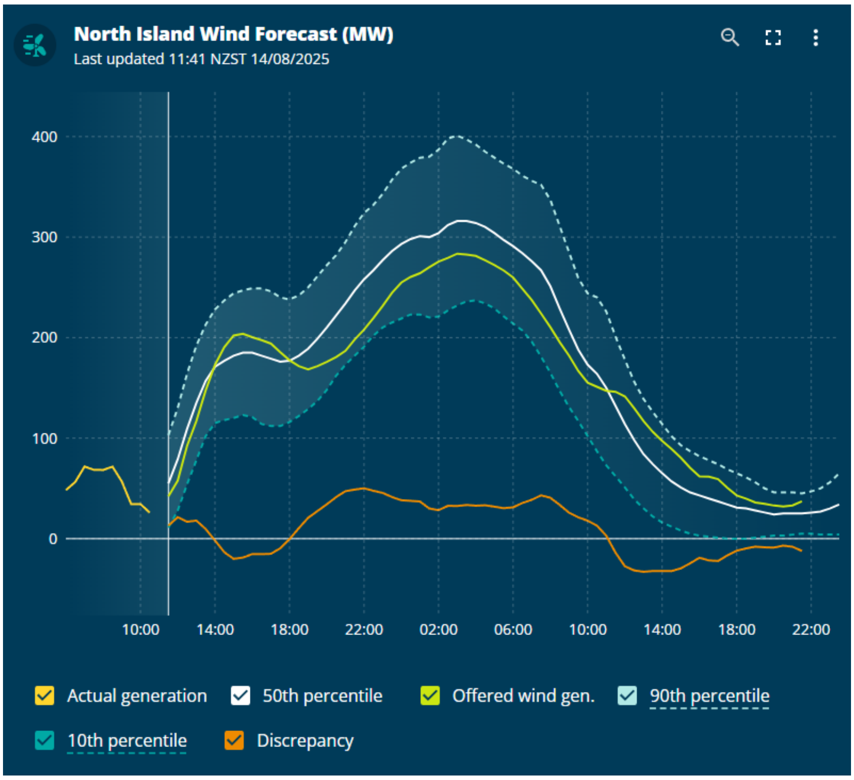
1. **AS EXISTING :** Attempt to maximise output to the electricity network, as has been the case traditionally, risking dispatch issues and variable market pricing, where there are periods of nil revenue each day, and resulting in the tie-break situation we are now debating. Vastly less than full output capacity would be sold to the electricity market. Renewables will output around 25% of the full incident energy each day, and as low as 0% if not dispatched.
2. **DUAL OUTPUT :** Generate using a mixed model, with both electricity grid connection, plus hydrogen supply via site installed electrolysers into the Natural Gas pipeline at fixed and predicable $/kg rates. Energy output not sold into the electricity grid is sold into the Natural Gas pipeline, with potential to sell 100% of all energy. This could result in 25% of incident energy to the electricity grid and 75% to the NG pipeline, increasing site revenue considerably.
3. **HYDROGEN ONLY :** Generate purely into the Natural Gas pipeline, where 100% of all incident solar/wind/geothermal/hydro energy will be sold as hydrogen, producing a relatively predicable and continuous revenue stream. This in effect is a 'hydrogen battery or

pumped storage'. Excess hydrogen is then injected into evacuated gas reservoirs, in the same manner as natural gas is at present. That stored gas provides a buffer to be used by larger gas turbines and fuel cells.

Options 2. and 3. enhance renewable green energy across New Zealand, and support an eventual transition to hydrogen gas, with increased reliability and system stability. Hydrogen gas in the pipeline can ultimately be utilised for gas turbine generators at strategic locations like Huntly, near critical load centres, providing voltage support, baseload reliable output, and frequency support. Such generators could be located even within city centres, as emissions from hydrogen combustion are negligible, plus fuel cells for smaller <5MW loads.

This is a new way to view energy, as both electricity and gas, working together.

'Surplus' wind energy that is already lost, as it cannot be reliably dispatched, is illustrated in the below extract from this 14th August 2025 snapshot on EM6, denoted "Discrepancy". Advance forecasting shows for the period 18:00 14th August to 11:00 15th August, the conservative 50th percentile energy lost is around 700MWh, which could otherwise be used for hydrogen production. If we assess this based on the 90th percentile it will increase to over 2,000MWh for that same period alone. Should a mere 500MWh of lost wind energy be converted to hydrogen with a 25% 'electricity – gas – electricity' conversion efficiency rate, that results in a 'pumped storage' equivalent of up to 500MWh per day, equating to a single 250MW Huntly generator running 2 hours per day, from renewable wind produced hydrogen gas.



Altering our thinking to an electricity system using hydrogen from wind, as pumped storage, gives the New Zealand energy system (both electricity and gas) considerably greater flexibility, durability and a renewable aspect that does not exist by use of fossil fuels. This will require industry wide collaboration and consultation, where the technology to achieve this already exists.

Question 4: Do you agree with our qualitative assessment that the benefits of the proposal can reasonably be expected to outweigh the costs?
With a prime driver for Transpower to enhance and encourage investment in new renewable generation, to establish fair market conditions, with clear rules for dispatch, a tie-breaker set of criteria is essential.
Question 5: Do you agree it is appropriate to rely on qualitative evaluation of the costs and benefits of the proposed amendments? If not, what information, evidence etc can you provide and/or what methods would you recommend to quantify the costs and benefits?
It is essential to base tie-break decisions on a qualitative evaluation of costs and benefits, with that focus being on system needs, both in terms of MW output plus voltage and frequency support.
Question 6: Do you think we should progress a proposal to incorporate information about any tie-breaker solution we decide to adopt into the Policy Statement, to enhance certainty and transparency?
Market certainty will enhance opportunities for generation investment, and as such is essential to develop and incorporate into the Policy Statement.
Any other comments:
In giving market assurances, to continue to encourage generation investment, the Tie-Break situation is an opportunity to open conversation on options not considered elsewhere, and to capture the wider energy market, including electricity-to-hydrogen and hydrogen-to-electricity, as a means to solve a number of issues facing both industries, and to enhance long term energy security. For this reason it would be useful to convene an industry wide energy forum for both electricity and gas, to work collaboratively.