System Operator Report

Dispatchable Demand bids in excess of Constraint Violation Penalty values

TRANSPOWER

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IMPORTANT

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1 Executive Summary

Dispatchable Demand (DD) was introduced into the wholesale electricity market in June 2014. The first participant in DD became active at 2 GXPs on 20 November 2014.

Shortly after the participant began bidding DD they raised questions around potentially inefficient market outcomes in certain situations. The specific issues raised are the inefficient dispatch of some demand and subsequent possibility for large constrained off payments to become due.

The Electricity Authority (EA) has requested the System Operator (SO) to provide technical expertise on a potential solution to address these issues. The SO's advice will enable the EA to propose changes to the Electricity Industry Participation Code 2010 (the Code) which will remove the market inefficiency.

The SO advises bidding DD at $600,000/MWh is sufficiently high to ensure load bid at that price will not be dispatched off. Equally the SO believes bids submitted at $600,000/MWh will not cause any undue price results in the market schedules.

2 Background

Dispatchable Demand (DD) is a market initiative which enables active demand side participation in the wholesale market. Approved participants submit bids representing their intended consumption of electricity. The bids contain quantity and price information. The price represents the maximum value the DD participant is willing to pay for the quantity of electricity indicated. Each bid can contain up to 10 tranches of price and quantity pairs. Multiple tranches allow the DD participant to signal the respective value they place on different components of their total electricity consumption. The higher the bid price, the more valuable (or more expensive to turn off) the load is to the DD participant.

DD bids are cleared in market schedules as part of the co-optimisation of energy and reserves which occurs when a schedule is solved. If electricity can be supplied to the DD participant at prices equal to or lower than their DD bid price then the bid is fully cleared.

If it is not possible to supply the electricity to the DD participant at a price lower than the DD bid price then the quantity cleared will be 0MW. It is possible for the DD bid to be marginal; the next cheapest MW to be brought to market is to adjust the cleared quantity of the DD bid. In this instance the DD bid may be partially cleared; the price at the GXP will be the marginal DD bid price.

DD participants are dispatched from the Non-Response Schedule Short (NRSS). Their dispatch instruction being the latest cleared quantity for their DD bid provided prior to the start of the trading period to which the cleared bid quantity applies. Normally dispatch instructions are issued to DD participants approx. 25mins prior to the beginning of the trading period to which they apply.

It is possible for DD participants to temporarily remove themselves from dispatch on a short-term basis. This is enabled by indicating whether the DD bid is dispatchable or non-dispatchable on a discrete trading period by trading period basis. For ease of convention all references to 'DD bids' contained in this paper refer to dispatchable bids.

When DD was envisaged it was thought all DD load would be explicitly metered[1]. Particularly if there was a split of load at a GXP between that which was genuinely dispatchable and that which was more of an 'always on' nature. In reality the active DD participant and prospective DD participants are using (or signal an intent to) use the Grid Owner's (GO) GXP meter. While this reduces costs to participate in DD and aligns with the Authority's desire to reduce barriers to entry it has resulted in inefficient outcomes which should be addressed.

The use of GO GXP metering results in an inability to remove the 'always on' load at the GXP, for which there is no intent to have dispatched, from participation in DD. Both the genuinely dispatchable and the 'always on' load are recorded by the GXP metering and consequently must be included in DD or not at all. To address this forced inclusion both the Authority and system operator advised the DD participant to bid the 'always on' load at a sufficiently high price such that it would not be turned off eg $50,000/MWh. It was intended that the high price bid would never trigger and therefore the 'always on' load could be just that.

3 The Problem

In the majority of situations the 'high bid price' advice works as intended. However it has subsequently become apparent that this accommodating advice does not deliver efficient outcomes when the NRSS schedule contains prices impacted by the presence of an infeasibility[2]. The infeasibilities can be local (driven by transmission issues), island-wide, or nationwide. A shortage of energy offers, reserve offers, or both is the most likely cause of island-wide or nationwide infeasibilities.

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[1] The settlement of DD requires the DD volumes to be explicitly metered for calculation of the constrained on and off payments due. Equally the inclusion of dispatchable bids in the final pricing schedule requires the removal of the load represented by the bid from the metering file. This is only possible if the DD load is explicitly metered.

[2] An infeasibility exists when the Scheduling, Pricing, and Dispatch (SPD) software cannot produce a solution without the use of a highly priced Constraint Violation Penalty (CVP, see Appendix 1). CVPs are reflected in nodal prices if the quantity of CVP required by SPD varies in the marginal cost of supply calculation.

When an infeasibility occurs the prices in the NRSS can exceed the 'high bid prices' resulting in a dispatch instruction to zero.

This is inefficient on 2 counts:

1. The load is shut down in response to a price which is not 'real', and
2. The resolution of infeasibilities in the final price schedule results in a settlement price lower than the 'high price bid', often much lower.

Concerning point 1, it is obviously inefficient to shut down a load unnecessarily; particularly when the bid price reflects the 'always on' nature of the load, and presumably therefore the desire for the associated use of that electricity to run uninterrupted.

The quantum of the discrepancy in point 2 can result in significant constrained off payments being made to the DD participant. These are due for every MW of load the DD participant turned off which final pricing says they should not have. For example if:

- 10MW of load is bid at $50,000/MWh,
- the NRSS 'price' is $105,000/MWh (results in a dispatch instruction of 0MW),
- the final price is $700/MWh, and
- the metered load is 0MW (ie they did shut down as instructed).

Then the DD participant would be due a constrained off payment of:

10MW * ($50,000-$700) = $493,000/2 = $246,500
(divided by 2 to convert from MWh to 30min trading periods)

This grossly inefficient payment is driven by the discrepancy between the 'high bid price' and the final price. While this phenomena can and does occur with economically priced dispatchable load the outcomes are much more sensible. In the above example any dispatchable load bid at a price lower than $700/MWh was correctly dispatched off with no payment due. If the load was bid at a price of $5,000/MWh the constrained off payment due would be $21,500. While this amount is still a substantial, it is infinitely more justifiable due to the plausibility of and economic justification for a $5,000/MWh bid price (c.f. a $50,000/MWh bid price).

4 Proposed Solution

The Electricity Authority (EA) has requested the System Operator (SO) to provide technical expertise on a potential solution to address these issues. The SO's advice will enable the EA to propose changes to the Electricity Industry Participation Code 2010 (the Code) which will remove the market inefficiency.

The proposed solution would result in all genuinely dispatchable DD bids being submitted at or below a maximum bid price of $15,000/MWh. Any load which is 'always on' must be submitted by DD participants at a bid price of $600,000/MWh.

The bid price limits are intended to address both the issue of inefficient dispatch and the issue of inefficient constrained off payments to DD participants arising from an infeasible NRSS. This is achieved by placing a ceiling on the bid price on the load which is genuinely dispatchable. The bid price ceiling limits the potential disparity between the 'incorrectly' dispatched off bid price and the final price; the price component of the constrained off payments. Thus, even if an infeasible NRSS dispatches this load off the inefficiencies which arise are economically justified.

The bid price of $600,000/MWh is designed to ensure load bid at this price will not be dispatched off when the NRSS is infeasible. If the 'always on' load is fully cleared in both the NRSS (DD dispatch) and final pricing schedules then there is no quantity difference upon which a constrained off payment is due.

In tandem these 2 bid limits eliminate the problem of inefficient dispatch of some load and the unjustifiable constrained off payments which arise from high bid prices. When those high bid prices indicate the desire to not turn the load off rather than the economic cost to do so.

5 ISSUES WITH PROPOSED SOLUTION

The EA has requested the SO to provide assurance that:

1. bids submitted at $600,000/MWh will function in the market system as intended (Always fully cleared), and
2. there will not be any unintended consequences from implementing this solution; for example $600,000/MWh bids setting the price.

6 SO'S EXPERT OPINION

The SO supports the proposed solution and gives its assurance, to the best of its knowledge at the time of writing, that bids submitted at $600,000/MWh will always clear and will not cause unintended consequences in the market schedules. This position is supported by the following observations:

SPD is a linear solver which co-optimizes the solution inputs to deliver the optimal solution within the confines of the constraints placed upon the solution. The optimal solution for the NZ Electricity Market is defined within the Code and is referred to as the objective function (Cl. 8 of Sch. 13.3 of The Code). Simply put it is to maximize the amount of scheduled load while minimizing the cost of scheduled generation and reserve.

CVP are required to allow SPD to find a solution when one would not have otherwise been possible based on the physical inputs provided to SPD. The simplest example of this is to consider a schedule were the required demand exceeds the offered generation; there is no physical solution where the requirement of

$$\textit{scheduled generation} \geq \textit{demand} + \textit{transmission losses}$$

can be satisfied in such a situation. In the absence of an alternative way to meet this requirement SPD would continue attempting to find a solution until it 'timed out'. This is not acceptable when you consider SPD is used in real-time to dispatch the power system and to prepare forecast schedules covering multiple trading periods when the results of the prior trading period become inputs to the following trading period. If no solution was reached by SPD the SO could not adequately assess the power system in real time and would have no visibility of the current situation. Equally forecast schedules would remain unsolved and consequently unpublished.

CVPs are the mechanism which allows a solution to be reached when one cannot be found based on the offered inputs (Generation, reserve, and Grid). Essentially CVPs are extremely high priced offers which SPD can use to satisfy the constraints within which its solution is bound. For example in the earlier situation where demand exceeds supply SPD can schedule a quantity of CVP to meet the shortfall of generation. This particular CVP is called Deficit Generation. Thus the equation of

$$\text{scheduled generation} \geq \text{demand} + \text{transmission losses}$$

can be represented as

$$\text{deficit generation} + \text{scheduled generation} \geq \text{demand} + \text{transmission losses.}$$

There are multiple CVPs (Appendix A) facilitating SPD to find a solution when faced with a myriad of impossible requirements. Many CVPs have both positive and negative values to allow solution for both 'overs and unders' situations. The previous example was an 'unders' deficit generation scenario.

CVPs are deliberately set to break in a prescribed order of preference; ie it is considered preferable to have deficit generation rather than to overload an asset or break a ramp-rate etc. This preference is signaled via the varied CVP 'prices'. Those 'prices' being set so high as to avoid any potential situations where a CVP might be used in preference to a physical offer. Equally CVP prices act as a signal to both the SO and the industry of an issue with a schedule. This occurs when the quantity of CVP present in a solution would change to supply the 'next MW', upon which marginal prices are based.

While CVPs have high 'prices' it is important to note that The Code explicitly prohibits settlement from taking place on prices where a CVP is present in the final pricing solution. This is enabled via the multiple clauses in Part 13 of The Code dealing with Infeasibility Situations and their resolution.

As mentioned previously SPD is a linear solver which delivers predictable and explainable results, it is 'un-emotive'. However to make the concepts more understandable it is easier to talk about some aspects in the humanistic terms of 'forced' and 'chooses'. In some situations SPD can be considered to be 'forced' take a certain action because there is no alternative. In other situations SPD can be considered to be making a 'choice'. However that 'choice' will always be governed by the objective function ie the 'choice' will be the lowest cost action.

Nodal prices are set by SPD at the level which represents the marginal cost of supply at each GXP. Simplistically this is often referred to as the cost of the next MW of supply to the GXP. The marginal cost of supply calculation will always be a 'choice' taken by SPD.

The following examples may help to illustrate 'forced' and 'choice':

SPD is 'forced' to break a down ramp rate when the equation

$$\text{initial MW} - \text{down ramp rate} \leq \text{max offered generation}$$

cannot be satisfied for that trading period. SPD is unable to schedule unoffered generation (for obvious reasons). When this happens the deficit between the offered down ramp rate and the required down ramp rate can be met by the deficit ramp rate CVP. The 'price' for this CVP is $850,000/MW, the most 'expensive' CVP. However SPD has no option but to 'buy' this CVP, without it a solution is not possible. In this way it can be seen that SPD was 'forced' to take this action.

An example of a CVP being used as a 'choice' is the situation when 3 non-identical supply transformers are in parallel supplying a GXP. The load required at the GXP causes scheduled flows over 1 of the transformers to reach its limit. Because the transformers are in parallel the laws of electricity mean no further supply is possible over the other 2 transformers either. If supply requirements have not been met at the GXP then the use of a CVP will be required. The obvious option is the deficit generation CVP. This will meet the shortfall at the GXP at a ‘cost’ of $500,000/MWh. However a cheaper option exists, the use of the deficit branch flow CVP at a ‘cost’ of $600,000/MW. The deficit branch flow option is cheaper because SPD does not need to purchase the same quantity of CVP as it does the 1:1 deficit generation CVP. If it purchases 1/3MW of deficit branch flow CVP for use on the limit of the binding transformer a 1/3MW will be able to be supplied over each of the other 2 transformers in parallel. Supply of the ‘next MW’ to the GXP would therefore be at a ‘price’ of $200,000/MWh (ie. 1/3MW * $600,000/MW CVP) plus the marginal cost of the supply of that MW from the offer stack.

The above example shows that SPD will only use more expensive CVPs when it is actually ‘cheaper’ to do so. This is key to the SO’s endorsement of the solution to bid at $600,000/MWh. The 2 most commonly used CVPs (deficit generation and deficit CE reserves) are both priced below $600,000/MWh. Those CVPs which exceed this value will only be used if SPD is forced to, in which case they will not be referenced in the marginal price, or if doing so delivers a cheaper outcome (many to one scenario).

SPD ‘chooses’ the marginal cost of supply; this will always be lowest cost. For example SPD will never decide to break an up ramp rate at $850,000/MW (Surplus ramp rate CVP) when the option exists to source the MW alternately at a cost of $500,000/MWh (Deficit generation CVP).

Further, deficit generation quantities do not require covering by reserves, therefore there is no possibility of the marginal energy price being the $500,000/MWh CVP price plus an additional component for reserves. The marginal energy price will be $500,000 irrespective of the quantity of deficit. Theoretically the entire solution could be met with deficit generation and not a single MW of reserve would be needed.

7 THE ALTERNATIVES

Two alternative solutions have been raised:

1. Ignoring ‘infeasible’ NRSS dispatch instructions, and
2. Bidding at a value (much) greater than the highest CVP value ie $10,000,000/MWH.

Both of these solutions are considered inferior to the proposed solution.

7.1 IGNORE INFEASIBLE DISPATCH INSTRUCTIONS

Under this proposal the market system would flag to DD participants if an NRSS solution was infeasible. The DD participant could then choose to ignore the resulting DD dispatch if they so wished. Constrained on or constrained off payments would not be made for the affected trading periods[3].

[3] It is unclear whether this prohibition would apply if the DD participant followed their dispatch instruction from an infeasible NRSS or not.

A solution which proposed ignoring dispatch instructions in certain situations sets a bad precedent concerning dispatch compliance. It is much simpler and less confusing to have a regime were all dispatch instructions must be complied with[4].

While it is possible for the Market System to identify whether an infeasibility is present in the solution it is likely this is too coarse for the purposes of this proposed solution. For example if a down ramp-rate is exceeded the down ramp-rate CVP at $850,000/MW will be present in the solution. However nodal prices are not impacted by the presence of this CVP in a solution. It would seem a poor outcome to become ineligible for constrained payments in this situation. Equally if there is a localized energy shortage at an unrelated GXP(s) the deficit generation CVP will be present in the solution. It will set the price at the affected GXP(s) but may not impact the price at the DD participants GXP.

However in some situations the presence of a deficit generation CVP will affect other nodal prices. For example in an island-wide or nationwide shortage the deficit will be assigned to those GXPs which incur the most transmission losses to supply 'real' MWs to; doing so minimizes the quantity of CVP used, reducing the objective function cost. In this instance the marginal cost of supply at the feasible GXPs cannot be derived from the offer stack, it has been exhausted. Rather the marginal cost of supply is derived from the change in CVP quantity in the solution; the 'next MW' at a feasible GXP will require an increase in CVP use at the infeasible GXP which has some physical supply. In these situations there will always be a GXP where supply is being met partly by physical supply and partly by the deficit generation CVP. The feasible GXP price will represent the savings to the schedule from avoiding transmission losses to supply the infeasible GXP ie the physical supply at the infeasible GXP decreases and the CVP supply increases. The feasible GXP price will be in the order of $490,000/MWh but supply at that GXP is 100% physical.

This last point is key to understanding a significant weakness with this proposal; it is highly problematic to define what constitutes a 'meaningful' infeasible dispatch instruction. The myriad ways in which an infeasibility may impact nodal prices and the quantum of impact are incredibly difficult to build a foolproof solution for. If you set the threshold to be the presence of an infeasibility it will trigger in situations needlessly, however if you made it GXP specific then nationwide, island-wide or regional issues may not trigger adequately.

7.2 BIDDING IN EXCESS OF ALL CVP VALUES

Under this proposal the price at which 'always on' load would be bid would (far) exceed the highest CVP price. The highest CVP price is $850,000 for ramp-rate violations. The logic behind this proposal was that even in the most extreme situations the bid price attached to the load would not be exceeded; the bid would always clear and the load would never be dispatched off.

While in theory this solution would also work it carries with it the risk of a phenomenon known in linear programming as 'poorly scaled models'[5]. Simply put the more divergent in size all of the variables within the solution being optimized are the greater the risk of an unexpected result.

[4] Noting the current operational exceptions contained in cl. 13.82 of The Code.
[5] See http://www.solver.com/excel-solver-problems-poorly-scaled-models

Further the SO does not believe that this solution presents any improvements over the proposed solution.

8 Conclusion

The SO supports the proposal to address inefficiencies with the existing DD design which occurs when an NRSS is infeasible by:

1. Capping the bid price of dispatchable load to $15,000/MWh, and
2. Requiring 'always on' load included in DD be bid at $600,000/MWh.

The SO does not foresee any unexpected consequences as a result of this proposal.

9 APPENDIX 1

Table 1: Constraint Violation Penalties (CVP) costs as at April 2015

Constraint name	CVP $/MW or $/MWh
Deficit 60s Reserve CE Price	$100,000
Deficit 6s Reserve CE Price	$100,000
Market Node/Trader Capacity Deficit Price	$160,000
Deficit Bus Gen Price	$500,000
Surplus Bus Gen Price	$500,000
Deficit Branch Flow Price	$600,000
Surplus Branch Flow Price	$600,000
Deficit Branch Group Constrained Price	$650,000
Surplus Branch Group Constrained Price	$650,000
Deficit M-Node Constrained Price	$700,000
Surplus M-Node Constrained Price	$700,000
Mixed Constraint Limit Violation Price	$750,000
Deficit 60s Reserve ECE Price	$800,000
Deficit 6s Reserve ECE Price	$800,000
Deficit Ramp Rate Price	$850,000
Surplus Ramp Rate Price	$850,000