System Operator TASC Report

Dispatchable Demand

Option 4 Detailed Analysis

24/10/2012

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

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Version	Date	Change
1	23/10/2012	Initial Draft
2	24/10/2012	Final

	Position	Date
Prepared By:	System Operator	

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1 Introduction

The Electricity Authority (Authority) has developed Code for their proposed Dispatchable Demand (DD) design at non-conforming GXPs. This design is also known as DD phase 1[1]. The final Code for DD phase 1 was gazetted on 20 October 2011.

On 20 September 2012, the System Operator (SO) supplied the Authority with a TASC report entitled *Dispatchable Demand Options Analysis* to provide analysis and information on an alternative design known as option 4.

This TASC report has been requested by the Authority in order to provide further information on option 4 and an assessment of the impact and risks of changing some of the design features included in option 1.

2 Background

It is important to encapsulate the difference between the gazetted Dispatchable Demand option (option 1) and the alternative option (option 4).

Option 1 (phase 1 and 2) delivers a complete solution that would work for any quantity of dispatchable demand. As a result, it is a solution with a lot of operational complexity and has high barriers to entry.

Option 4 has been developed on the assumption that the quantity of dispatchable demand entering the market is most likely to be at a level at which the System Operator believes no quality and reliability issues will arise. Therefore project costs and barriers to entry can be reduced by treating dispatchable demand as a pricing product rather than a security product. This keeps the design simple, and enables a significant reduction in the projected cost of the project by removing the need to have the same reliability and robust design and the need to integrate with other operational systems.

A sizeable portion of the option 1 costs are introduced by the need to change Real Time Dispatch (RTD). RTD is one of the System Operator's most critical operational processes, and any changes to RTD require significant testing and thorough integration and business process design.

Option 4 avoids the need to change RTD by recognising that the demand that we will be dispatching is less than the variation experienced on the system due to other factors such as wind and other (non-dispatchable) demand. Therefore there is no immediate need to treat dispatchable demand as a security product.

Option 4 allows us to meet the Authority's key principles for a dispatchable demand regime, avoid operational complexity and build a model that:

- Will encourage participation; and
- Can be extended at a later stage if the uptake of DD is significant and requires DD to be treated as a security product in the future; and
- Has an acceptable cost benefit.

[1] Phase 2 is to implement dispatchable demand at conforming GXPs. Code has not been developed for phase 2.

3 Dispatchable Demand and System Security

As stated in section 2, the design of option 4 is based upon the assumption that the quantities of load participating in DD will be low enough to not create system reliability issues.

This raises the question of when does it become a reliability issue, and is that point far enough into the future to warrant a delay in investing in operational systems?

It is far too simplistic to say there is a single number at which operational issues arise[2]. Some years ago many people around the world were predicting numbers at which wind generation could no longer be tolerated on power systems. This line of thinking ignores the complex interactions between uncontrolled variables on the power system and, more importantly, it ignores the ability to adapt engineering and market systems to cope with these variables.

As with wind, the System Operator believes there is no single number but that a number of steps and adaptations can be put in place before a major reinvestment in operational DD systems is required.

[2] It is not possible to provide a one size fits all number, as this does not take into account information on the time of day, seasonal information, load inertia at the time, system voltages and abnormal system conditions such as loss of circuits, market dynamics, plant availability or contingent events. For example, the system can cope easily with Pacific Steel and 50 MW step changes during the day, but at night the frequency keeper struggles with it. The dispatcher has recently had to cope with 200 MW of wind generation coming off over a 5 minute period during the day, and this was manageable. So, the volume of DD is very dependent on system conditions at the time.

4 Summary of design differences and risk

	Option 1	Option 4	Option 4 Risk Assessment
RTD-based dispatch	5 minute dispatch from RTD	5 minute[3] dispatch from non-RTD schedule	• Option 4 reduces risk and cost by avoiding the need to change complex operational tools and processes associated with RTD. • May require changes in the future to accommodate growing DD, but Option 4 costs and development effort will not have been wasted.
Electronic Dispatch	Electronic dispatch via Genco	Dispatch via WITS	**Low risk** • Communications links are not monitored closely, but this is not essential. • It should be possible to configure WITS to send dispatch instructions to participants
Back up tools	Dispatch from back up tools (SAD)	No dispatch from SAD	**Low risk** • Unplanned use of SAD is rare. Planned use of SAD occurs during off peak periods when the need for DD is unlikely. • SAD is not a Code requirement.
Co-optimisation	DD and IL are co-optimised	DD and IL are **not** co-optimised	**Low risk** • Demand and IL are currently not co-optimised. This provides purchasers with more control of their own decisions on load use. • Only a very small number of electricity users would benefit from a co-optimisation service.
Ramp rates	Dispatch bids include maximum ramp up and ramp down information	Dispatch bids do **not** include ramp rate information	**Low risk** • Ramp rates are not essential for dispatch, final pricing and settlement.
Compliance	Compliance is assessed via real time SCADA indication and is measured every 5 minutes	Compliance is assessed ex post and is measured over the trading period	**Low risk** • Compliance process for both options is still undefined. • Option 4 allows for compliance to be assessed ex post.
Approvals	Purchaser applies to SO for a specific load to become a dispatch capable load station	Purchaser must meet metering standards for final pricing and compliance purposes	**Low risk** • Approval process for both options is still undefined. • Option 4 retains a streamlined approval process to ensure that metering and compliance standards can be met.
Participation at conforming GXPs	No. Non-conforming GXPs only	Yes	• Achieved by modelling the dispatchable part of an existing conforming GXP as a new non-conforming GXP • Puts obligation on purchasers wishing to be dispatched to submit bids at all times (whether dispatchable or not) but greatly reduces cost of change to the Market System.

[3] Option 4 can deliver either a 30 minute or a 5 minute dispatch solution. This requirement is not confirmed and requires further analysis. See section 6.7.

5 Option 4: Cost, Timeline and Risk Factors

Item	Timeline	Cost estimate
Detailed Design & Business Case (BC3)	▪ 5 months to develop ▪ Deliver in April 2013[4]	$469,714
Build to closeout	▪ 12 months implementation ▪ 3 months close out ▪ Go-live in April 2014	$1,963,872
Subtotal		**$2,433,586**
IDC		$141,748
Contingency (25%)		$643,834
Total		**$3,219,168**

This cost and timeline estimate was developed by taking the information used for the option 1 Initial Business Case (BC2) as a baseline and making the following adjustments:

- Removing cost associated with resource no longer required; and
- Scaling down the resource profiles and timelines to account for design simplifications.

A 25% contingency is included to reflect that fact that the project is still in the high level design phase. See section 5.1 below for more detail.

5.1 Detailed Design Breakdown

More information on the detailed design is provided in the table below.

Detailed Design Activities	Cost estimate
▪ Stakeholder requirements[5] refresh ▪ Detailed Design Document development ▪ Solution requirements gathering - Functional requirements - Non-functional requirements - Market Operator Interface (MOI) requirements ▪ NZX interface specifications development ▪ Transition requirements gathering ▪ Training requirements (high level) gathering ▪ Business process requirements (high level) gathering ▪ Test Plan development ▪ Communications Plan development ▪ Detailed Business Case (BC3) development - Project Plan from Build to Go-live and Closeout - Cost Estimate for SO component of the project (includes contingency of 6%)	$469,714
IDC	$16,218
Contingency (25%)	$121,483
Total	**$607,415**

[4] Assumes detailed design starts in mid-November 2012. December and January are treated as one month (due to staff absences over the Christmas and New Year period).
[5] Includes Transpower, the Electricity Authority and NZX.

On 28 June 2012, the SO supplied the Authority with an Initial Business Case (BC2) based on the gazetted Code for Dispatchable Demand. This design is known as option 1. The BC2 indicated that the SO could implement the required changes at an estimated cost of $4.8 million.

The **option 1** costs were developed by:

- Identifying the resources (SO and IST staff) required for the project;
- Allocating staff time required for specific activities during the detailed design phase;
- Allocating a percentage of staff time for the implementation (post BC3) phases of the project (build, test, training etc.);
- Obtaining quotes from external suppliers (such as Alstom and Red Rock) for the detailed design and implementation phases; and
- Adding on costs for interest during construction (IDC), foreign exchange and contingency.

The cost estimate for the detailed design phase is based on actual activities. The costs for the implementation phase (post BC3) are less robust, but will become better defined as we work through the detailed design process. This is to be expected at this stage of the project.

We did not have sufficient time to undergo a full BC2 process for option 4. The **option 4** costs were developed by:

- Taking the option 1 costs as a baseline;
- Removing cost associated with resource no longer required (such as SCADA and Genco engineers);
- Scaling down the resource profiles and timelines for the other SO and IST staff who are still required;
- Scaling down the quotes from external suppliers. We did not have time to obtain new quotes; and
- Adding on costs for IDC, foreign exchange and contingency.

5.2 Risk Factors

The timeline presented is an unconstrained view of the project. It does not take into account resourcing and other constraints across the EA/SO programme of work. The timeline also assumes that the required Code changes and consultation are performed in parallel with the detailed design work.

The key risk with performing the Code changes in parallel is that the final Code will be gazetted after the delivery of the Detailed Business Case (BC3). Any significant changes introduced through the consultation phase are likely to impact on the agreed cost and timeline. However, this situation is similar to what was experienced on DSBF[6]. The Authority can control this risk by:

- Continuing to work closely with the System Operator; and

[6] The DSBF BC3 cost and timeline was agreed in June 2011. The Final DSBF Code Amendment was gazetted in October 2011.

- Keeping the design simple in order to keep costs and barriers to entry low; and
- Not introducing significant change part way through the detailed design and consultation process.

It is suggested that the SO and the Authority agree appropriate interim milestones between the start and end of the detailed design phase in order to monitor and manage these risks. This will provide the opportunity to re-plan the approach or re-scope if any significant issues arise.

The Detailed Business Case (BC3) will produce a more robust cost estimate and timeline, and will also take into account any resource constraints.

5.3 Extending the solution

Option 4 also provides the Authority with the choice of extending the design at a later date to include RTD-based dispatch and the other design features[7] associated with option 1 if these design features are proven to be necessary in the future.

This development path is possible because the system changes introduced under option 4 are also required for an extended (option 1) solution and will not go to waste. For example, both options require the following system changes to be made:

- Changes to WITS displays to allow purchasers to submit dispatchable bids, and to allow purchasers to view cleared dispatch bid quantities. Bid validation is performed by WITS;
- Changes to interfaces to send dispatchable bid information from WITS to the Market System and vice versa;
- Including dispatchable bids in all schedules (except RTD); and
- Changes to the Market Database (MDB) to process and validate dispatchable bid information; and
- Changes to the final pricing processes; and
- Calculating constrained on and constrained off payments for purchasers.

The System Operator has not identified anything to date that would be not used with an extended solution.

Pursuing an extended RTD-based solution would be complex and costly, but would not cost as much as the full $4.8 million estimated for option 1. This is because there are overlaps between the option 1 and option 4 designs (as noted above), and cost savings could also be made in area of regression testing.

[7] Such as co-optimisation and electronic dispatch

6 Analysis of design differences and risk

This section of the report describes in detail:

- the differences in some of the design features between option 1 and option 4;
- the reasons for omitting or changing these design features in option 4; and
- the impact and risk of the changes.

6.1 RTD-based dispatch

Real Time Dispatch (RTD) is the schedule used by the SO to formulate dispatch instructions. RTD is automatically run every 5 minutes and looks ahead 5 minutes (i.e. it is a forecast of where the power system will be in the next 5 minutes). The dispatcher can manually run an RTD schedule between 5 minute intervals if required and does so for security purposes.

6.1.1 Options design summary

Option 1	Option 4
Dispatchable bids are included in RTD.	Dispatchable bids are **not** included in RTD.
The System Operator issues demand dispatch instructions to a purchaser based on RTD results.	Purchasers are dispatched from a non-RTD schedule (see section 5.7 for discussion on different options).
Generators and ancillary services agents are issued dispatch instructions from RTD.	Generators and ancillary services agents are issued dispatch instructions from RTD.

6.1.2 Impact and risk

RTD-based dispatch was excluded from option 4 in order to avoid the need to change critical operational processes, and therefore reduce costs and barriers to entry. The System Operator regards demand dispatch from a non-RTD schedule as low risk. The reasons are set out below.

RTD is primarily an operational tool, not a pricing tool. Its primary purpose is to allow the dispatcher to issue dispatch instructions and to ensure that the system is balanced in real time. RTD is one of the System Operator's most critical operational processes, and any changes to RTD require significant testing and thorough integration and business process design

Very little information is published to WITS from RTD[8]. This is deliberate, as it allows the co-ordinator to manage dispatch of the power system without needing to be concerned about non-operational issues. It provides the dispatcher with the

[8] Binding constraints are the only information published to WITS from RTD.

flexibility of being able to run a test RTD solve[9] and analyse the results before choosing whether or not to dispatch the instructions[10].

Option 4 has been developed on the assumption that the quantity of dispatchable demand entering the market is likely to be at a level at which the System Operator believes no quality and reliability issues will arise. Therefore project costs and barriers to entry can be reduced treating dispatchable demand as a pricing product rather than a security product. This keeps the design simple, and enables a significant reduction in the projected cost of the project by removing the need to have the same reliability and robust design and the need to integrate with other operational systems.

Option 4 avoids the need to change RTD by recognising that the demand that we will be dispatching is less than the variation experienced on the system due to other factors such as wind and other (non-dispatchable) demand. Therefore there is no immediate need to treat dispatchable demand as a security product.

Option 4 allows us to avoid operational complexity and build a model that:

- Will encourage participation; and
- Can be extended at a later stage if the uptake of DD is significant and requires DD to be treated as a security product in the future.

Advantages of non-RTD dispatch:

- Market system changes are cheaper because the changes do not touch RTD and therefore do not incur significant costs associated with testing, integration with other operational systems and business process changes.
- Non-RTD dispatch allows us to keep participation costs low. RTD-based dispatch drives us down the path of high participation costs (e.g. metering/communications) because dispatchable demand is a "security product". Security products also require tight compliance.

Disadvantages of non-RTD dispatch:

- Generation and reserves will continue to be RTD-based dispatch. This will open up a difference between the schedules used for dispatching different parts of the system. That is not ideal in principle, but is a practical solution if we accept that DD is not a security product.
- Because DD and IL are not dispatched from the same schedule, co-optimisation between demand and IL is not possible. See section on co-optimisation for more information on the impact and risk.

6.2 Electronic dispatch

Electronic dispatch refers to the system that the System Operator uses to deliver dispatch instructions to Gencos.

[9] For example, the dispatcher may want to test the impact of turning on the HVDC, or changing HVDC directions in order to meet changing system conditions in the next 5 minutes. The Real Time Pricing (RTP) schedule was developed to provide participants with a real time view of the price and allow RTD to remain unpublished.

[10] Dispatch instructions can be sent to all participants, or to a subset (e.g. to deal with regional issues).

Genco communication is used by generators, IL providers and the HVDC operator to receive and acknowledge dispatch instructions. The electronic dispatch system allows the dispatcher to monitor the communications link between the SO and each Genco server. The electronic dispatch facility also has redundancy in case of communication or server failure.

6.2.1 Options design summary

Option 1	Option 4
The System Operator issues demand dispatch instructions to a purchaser via a Genco terminal.	Dispatch quantities are published to WITS. WITS could potentially push the dispatch quantity to purchasers (needs further investigation and discussion with NZX).
The Genco terminal provides acknowledgement of receipt of instruction	Acknowledgement of the dispatch quantity is not provided (although this needs further investigation and discussion with NZX).
Generators and ancillary services agents are issued dispatch instructions in the same way (via Genco).	Generators and ancillary services agents are issued dispatch instructions via Genco.

6.2.2 Impact and risk

Electronic dispatch was excluded from option 4 in order to reduce costs and barriers to entry associated with the set-up of Genco and a dedicated communications link. The System Operator regards demand dispatch signalled from WITS to be low risk. The reasons are set out below.

Building on the assumption that DD is not a security product, we can extend this assumption to assert that electronic dispatch and the features it provides such as acknowledgement, monitoring and redundancy are not required.

Under Option 4, dispatch quantities (cleared dispatchable bid quantities) will be published to WITS. Cleared quantities from the forecast schedules (WDS, PRS and NRS) are already published to WITS, so it is not a big change to publish any extra information on cleared bid quantities to WITS.

WITS is already configured to provide participants with emails and text message reminders for a number of events (e.g. SRC notices), so we have made an assumption that dispatch quantities could be "pushed" to participants[11] using existing functionality in WITS, although this will need to be confirmed with NZX.

However, we have also assumed that WITS does not acknowledge receipt of information. While acknowledgement of dispatch instructions would appear to be a desirable feature, it is not required for dispatchable demand in the initial stages. This is because under option 4, DD is not a security product and therefore does not require tight monitoring in real time like generation. It is also

[11] Rather than requiring purchasers to constantly monitor WITS displays for their cleared quantities.

important to note that acknowledgement of the dispatch quantity does not guarantee compliance with the instruction[12].

Advantages of electronic dispatch:

- Receipt of the dispatch instruction is monitored. Genco allows acknowledgement of the dispatch instruction to be provided.
- Connection of communications link between the purchaser and the SO is monitored and has dual redundancy – i.e. we should know that the instruction has been received and if there are any problems.
- Any problems such as loss of Genco connection and dispatch non-acknowledgement are alarmed to the dispatcher.

Disadvantages of electronic dispatch:

- Pushes costs of setting up a communications link and Genco onto purchasers (and therefore is an additional barrier to entry).

6.3 Standalone Dispatch (SAD)

Standalone Dispatch (SAD) is the SO's emergency backup tool that is used for dispatch when the normal market dispatch tools are unavailable.

<u>Dispatch under normal circumstances:</u>

- Participants upload bids and offers via WITS
- This information, along with other information is stored in the Market Database (MDB). The SO's Scheduling, Pricing and Dispatch (SPD) tool uses this information to produce the market schedules.
- Schedule results from the WDS, NRS, PRS and RTP are published to WITS.
- RTD dispatch instructions are issued via Genco.

<u>Dispatch from SAD:</u>

- Is used for dispatch when there are planned and unplanned outages of the Market System.
- There is no connection to the MDB and WITS while on SAD.
- This means that schedules are not published to WITS while dispatch is from SAD. Bids and offers cannot be uploaded via WITS[13]. Bona fides must be phoned through to the dispatcher. Participants can still see information from old schedules on WITS.
- The latest NRSS, NRSL and some of the current dispatch data is uploaded to SAD for the purposes of dispatch.
- This information is used to produce RTD schedules while on SAD[14].
- Dispatch instructions from SAD are issued via Genco.

[12] Acknowledgement of the dispatch instruction is likely to be a legacy from the era of phone dispatch where a generator provided acknowledgement of the instruction over the phone.
[13] They will stay in the bid and offer pipe until the system is back up.
[14] These schedules are produced by SPD, or by a parametric solve.

- Information (e.g. dispatch instructions) from SAD is uploaded back to the MDB when the Market System is available again.

6.3.1 *Options design summary*

Option 1	Option 4
Dispatchable bids are included in the NRS. The NRS is uploaded to SAD.	Dispatchable bids are included in the NRS. The NRS is uploaded to SAD.
Purchasers can continue to receive dispatch instructions while the SO is on SAD.	Purchasers do **not** receive dispatch quantities while the SO is on SAD.
Dispatch instructions are received via Genco.	DD is suspended for the duration that the SO is on SAD.

6.3.2 *Impact and risk*

SAD was excluded from option 4 because SAD requires RTD-based dispatch and electronic dispatch via Genco which are not features of the option 4 design (see sections 5.1 and 5.2). The System Operator regards the omission of DD from SAD to be low risk. The reasons are set out below.

SAD is an emergency backup tool. The primary purpose of SAD is **not** to provide optimal dispatch, but to maintain dispatch (and therefore security) when the primary dispatch tools are unavailable.

Unplanned use of SAD is rare. Planned use of SAD[15] occurs during off-peak periods when the need for dispatchable demand is unlikely. Therefore omitting DD from SAD is low impact. It should also be noted that SAD is not a Code requirement but is tool specified in the SO's Disaster Recovery Plan in order to meet the SO's software back up requirements under the SOSPA.

Advantages of dispatch from SAD:

- Dispatch is maintained under emergency situations.

Disadvantages of dispatch from SAD:

- Pushes costs of setting up a communications link and Genco onto purchasers (and therefore is an additional barrier to entry)

6.4 DD and IL Co-optimisation

Co-optimisation refers to functionality provided by SPD. SPD currently co-optimises the cost of energy and reserves. This means that SPD will determine

[15] Required for major upgrades of the Market System

the overall least cost (optimal) solution to provide the required energy to meet demand **and** reserves to meet the largest risk in each island.

It is possible for SPD to co-optimise the cost of providing dispatchable demand and interruptible load (IL), but this is currently not provided.

6.4.1 Options design summary

Option 1	Option 4
DD and IL are co-optimised in all schedules.	DD and IL are **not** co-optimised in any schedule.

6.4.2 Impact and risk

Co-optimisation was excluded from option 4 because co-optimisation requires that demand and IL are dispatched from the same schedule. This requires DD to be RTD-based dispatch which is not a feature of the option 4 design (see section 5.1). The System Operator regards the omission of DD and IL co-optimisation to be low risk because this is a feature that is currently not provided and is a service that only very few participants are likely to benefit from. More detail is set out below.

DD and IL co-optimisation requires:

1. Demand and IL to be dispatched from the same schedule; and
2. DD and IL to be offered and delivered from the same location, and
3. SPD and RMT[16] to iterate.

Co-optimisation is likely to be of benefit to parties such as Norske Skog who will offer IL from a machine and submit a nominated dispatch bid for that exact same machine. The driver for co-optimisation is to ease or remove decision making for the purchaser.

However, co-optimisation would not be possible where one participant (e.g. Vector) offers the IL and another participant (retailers) bid the load. Co-optimisation is only possible where there is an exact match between a bid and an IL offer in terms of the load it covers. Because of this, co-optimisation is likely to be beneficial to a small number of parties who offer IL at specific GXPs.

Advantages of DD and IL co-optimisation:

- Eases decision making for the purchaser wishing to optimise financial returns.

Disadvantages of DD and IL co-optimisation:

- Co-optimisation transfers the economic decision from the participant to the System Operator (along with the risk). It removes ability for the purchaser to choose how to optimise IL and DD. SPD will determine the least cost solution (nationally), but this may not be in the purchaser's interest.

[16] The Reserve Management Tool

- Removes flexibility from the purchaser as it requires that IL is offered at the same location as demand. IL is currently not always offered at the GXP at which it is delivered. This is because IL is cleared on an island level.
- Untested stability issues are possible due to the need for SPD and RMT to iterate.
- Introduces costs associated with changing SPD.

6.5 Ramp Rates

Ramp rates provide information on how fast a generator or dispatch capable load station can respond to a dispatch instruction within a defined period (5 minutes or 30 minutes).

6.5.1 Options design summary

Option 1	Option 4
Dispatchable bids include maximum up ramp rate and maximum down ramp rate information.	Dispatchable bids do **not** include ramp rate information.
Ramp rate information is included in all schedules	Ramp rate information (for demand) is **not** included in any schedule.

6.5.2 Impact and risk

Ramp rates were excluded from option 4 as ramp rates require real time SCADA information to be incorporated into and validated by the Market System. The need to set up SCADA indications also pushes costs onto purchasers. Therefore option 4 reduces cost by eliminating the need to include and validate the SCADA information in the schedules. The System Operator regards the omission of ramp rates as low risk. The reasons are set out below.

As noted above, ramp rate information is only of use if you have a starting point, or initial condition. For example, in order to determine where a generator or load can move to within the next 5 minutes, SPD needs to know what that generator or load's output is (in MW) at the current point in time. For generation, we measure the generator's output using real time indications from SCADA. These values and checked using a tool known as SCADA Data Validation (SDV).

While SCADA indications are nice to have, they are not essential for determining a dispatch quantity. The reasons for including ramp rates would be in case dispatch load stations are genuinely quite slow to ramp towards dispatch instructions and to give dispatch load stations another tool for managing yo-yo dispatch[17].

[17] The term yo-yo dispatch is used to describe a load that is setting the marginal price. As a consequence, it is possible for this load to be dispatched up and down a number of times during a trading period. A

It should be noted that ramp rates are more likely to bind in the 5 minute schedules, and do not tend to bind in the 30 minute schedules. If a dispatched load is genuinely slow to ramp, but compliance with the dispatch instruction is measured and assessed over a half hour trading period, then the need for ramp rate information is reduced (see compliance - section 5.6). While ramp rates take into account some information about the ability for a dispatched load to respond to a dispatch instruction, there are still other scenarios under both options 1 and 4 where a load station may be issued a dispatch instruction that they cannot comply with[18].

In the case of yo-yo dispatch, a dispatch load station can and should manage the problem by submitting a bid price that is not marginal. This is the method used by generators when submitting their offers.

Advantages of ramp rates:

- The purchaser's ability to respond to a dispatch quantity is taken into account.

Disadvantages of ramp rates:

- Pushes set up costs on purchasers by requiring them to set up real time SCADA indications that must be sent to the System Operator.
- Adds cost to the design by requiring the SCADA information to be integrated into the Market System and validated by the SO's tools.
- May not add much value if other information, such as whether the load can respond to a partial dispatch[19] quantity, is not taken into account.

6.6 Compliance

Compliance is a term used to refer to whether a market participant operates in accordance with its dispatch quantity, and how this is measured and assessed. This is a function performed by the Authority.

Compliance is important for a number of reasons:

- **For security –** to ensure that when the SO issues dispatch instructions, it can rely on these instructions to be followed and therefore for the system to remain secure and balanced.
- **For robustness of final pricing –** Offers (and bids under DD) are included in the final pricing schedule. These offers are used to determine the final spot price for energy and reserves. Therefore the compliance process helps to ensure that these offers (and bids) are a reasonable estimate of its actual output and are therefore suitable and robust enough to be used as an input for final pricing.

down ramp rate could be bid at 9999 MW/min while the up ramp rate could be set at 0 MW/min: that would allow the load to be dispatched down but not back up again until the bids were revised.

[18] An example is partial dispatch.

[19] The term partial dispatch is used to describe loads that can either be on or off ("binary loads"). A binary load cannot meet an instruction for only part of the load.

- **To minimise constrained on and constrained off costs** – Offers (and bids under DD) are also used as an input into determining constrained and constrained off payments[20].

6.6.1 *Options design summary*

Option 1	Option 4
A dispatched load is required to operate constantly at its dispatch point.	A dispatched load is required to operate to its average dispatch quantity over the half hour.
Fine data could be used to assess compliance (e.g. 7 second indications). This data would be provided in real time via SCADA.	Metering data would be provided ex post to assess compliance. This does not need to be provided in real time.
There is one compliance standard for all purchasers (i.e. all purchasers must provide 7 second SCADA data).	The Authority may choose to apply different standards depending on the size of the purchaser. e.g. Small purchasers (less than a certain level of MW) may provide 1 minute data, but large purchasers must provide 7 second data.

6.6.2 *Impact and risk*

Option 4 requires purchasers to submit metering data (or other data suitable for assessing compliance) after real time. This was done in order to reduce the set up costs for purchasers and integrating this information into the Market System. The System Operator regards compliance assessment performed ex post to be low risk. The reasons are set out below.

If RTD-based dispatch is used, then the preference would be for constant compliance assessed using very frequent load indications. Constant compliance would be required (as for generation) because dispatchable demand would be a “security product”.

If non-RTD-based dispatch is used (as is used in option 4), then the main reason for requiring compliance is to ensure the integrity of pricing. It would not be important to monitor compliance in real time because RTD is used to manage security and dispatch generation, and RTD would not be affected (the SO would be in the same position it is now).

If non-RTD dispatch is based on a half hour schedule, then it would be preferable to assess compliance on average over the 30 minutes. This could be done using 30 minute metering data ex post (e.g. next day).

If non-RTD dispatch is based on a 5 minute schedule, then we could use 30 minute metering data ex post to assess compliance with the average dispatch

[20] Although constrained on and constrained off payments are based on the lesser of the average dispatch instruction and the reconciled quantity (whichever is relevant), therefore this provides another incentive for generators and purchasers to comply with their dispatch instruction.

quantity. This should be acceptable if pricing remained on a 30 minute basis. If pricing moved to a 5 minute basis in the future, the purchaser could be required to submit metering information at finer intervals.

As the key driver for compliance is robustness of final pricing, and final pricing is a half hour schedule, then it is probably sufficient for the compliance requirement to be the average over the half hour (rather than continuous).

6.7 30 minute dispatch vs. 5 minute dispatch

The System Operator's 20 September 2012 TASC report entitled *Dispatchable Demand Options Analysis* proposed that demand could be dispatched on 30 minute basis based on the results of the PRSS.

The Authority's letter of 4 October 2012 queried whether a move from 5 minute dispatch to 30 minute dispatch would introduce any market inefficiencies. This section of the report is a discussion of this point.

6.7.1 Options design summary

Option 1	Option 4
5 minute dispatch	Options are: • 30 min dispatch off PRSS • 5 min dispatch off RTP • 5 min dispatch off a copy of RTD

6.7.2 Impact and risk

30 minute dispatch was initially suggested for its simplicity, but the advantages disadvantages need to be analysed and assessed against the advantages and disadvantages of 5 minute dispatch.

Option 4 can deliver either a 30 minute or a 5 minute dispatch solution. Therefore the decision on which solution to pursue does not need to be made immediately and can be made during the detailed design phase until further analysis has been undertaken. Industry consultation with current and potential DD participants is also recommended.

Advantages of 30 minute dispatch:

- Removes barriers to entry by reducing the potential operational problem of yo-yo dispatch. Yo-yo dispatch can still occur, but will happen every 30 minutes between trading periods rather than every 5 minutes.
- Dispatch quantities are less volatile.
- Matches more closely to the final pricing calculation of prices based on the contracted position at the beginning of the trading period.

Disadvantages of 30 minute dispatch:

- Does not allow demand to respond when it is needed – i.e. to manage system peaks or to re-balance the power system following an event.

- Events that occur within the 30 minute period will not impact on the final price. This is because final pricing is based on initial conditions at the start of the trading period (and also does not take discretionary constraints and bona fides into account). However, an event will impact on constrained on and off payments as expensive generation will need to be constrained on, but maybe it was cheaper to dispatch demand off.
- It is difficult to predict load over a 30 minute period and the 30 minute dispatch instruction may under or over dispatch load.
- Purchasers may build their systems to respond to a 30 minute dispatch instruction. This may make it difficult to move to 5 minute dispatch and 5 minute pricing in the future.

7 Participation at Conforming GXPs

This section provides detailed information about how the SO proposes to allow purchasers at a conforming GXP to participate in Dispatchable Demand under option 4, and why the proposal is potentially so difficult and costly under option 1.

7.1.1 Options design summary

Option 1	Option 4
Requirements for DD at conforming GXPs are undefined	Allows participants at conforming GXPs to participate in DD
Assumes phase 2 is delivered as a separate project later	This is achieved by creating a new non-conforming GXP

7.1.2 Recap of the existing system

In the current system the inputs at a conforming GXP are:

- The Load Forecast
- Difference Bids (optional)

The Load Forecast application uses SCADA load data and weather data (actual and forecast) to determine the demand forecast at an area level. MV90 data from the previous week is used to determine the load at a GXP level.

7.1.3 Requirements for DD at conforming GXPs

The Code for dispatchable demand at conforming GXPs (phase 2) has not been developed. One of the key challenges with implementing DD at conforming GXPs is the (potential) need to modify the Load Forecast. See section 7.1.4

The answers to the following questions are required from the Authority in order to determine the requirements for DD at conforming GXPs:

- What obligations should be placed on purchasers at a conforming GXP? Should dispatchable-capable purchasers at a conforming GXP be required to submit bids all the time, or only for when they have elected to be dispatchable?
- Can a purchaser at a conforming GXP change from being dispatchable to non-dispatchable and vice versa?
- Should purchasers be dispatched using information from a dispatchable difference bid or a dispatchable nominated bid?

7.1.4 Dispatchable Demand and the Load Forecast

The Load Forecast application uses SCADA load data and weather data (actual and forecast) to determine the demand forecast at an area level. MV90 data from the previous week is used to determine the load at a GXP level.

The load forecast uses this information to ‘learn’ behaviours and needs a history of data to build up its knowledge of purchaser load profiles. Taking purchasers in and out of the load forecast will affect the ability to 'learn' and its forecasting ability.

There is currently no feedback loop for the load forecast to take into account any changes in demand as a result of dispatchable demand. Some kind of feedback loop would need to be designed if the Load Forecast is expected to continue to provide useful forecasts for the use in forward looking schedules.

The need for a feedback loop is further complicated if the design requires that purchasers at conforming GXPs have the ability to change between dispatchable and non-dispatchable up until gate closure (and even after gate closure in the case of a bona fide). The Load Forecast will need to be modified to take this design requirement into account.

7.1.5 Options for implementing DD at conforming GXPs

There are a number of ways that DD at conforming GXPs could be handled. The approach for Option 4 is presented below. The requirements for Option 1 Phase 2 are still unknown, but an example is provided below for discussion.

Option 4[21]

Purchasers at conforming nodes that wish to have the ability to be dispatched (off) will have this load modelled at a separate market node (i.e. a separate non-conforming GXP). There will be a requirement for the purchaser to provide metering at this node.

The purchaser will have an obligation to provide a bid to the system operator for all trading periods, whether or not the purchaser has elected to be dispatched. When the purchaser elects not to be dispatched their bid will be a non-dispatchable nominated bid, When the purchaser elects to be dispatched their bid will be a dispatchable nominated bid. .

Key points:

- These purchasers will no longer have their load forecast by the system operator's central load forecast; they will provide bids[22].
- The dispatchable nominated bids will be used in final pricing.
- This approach requires Code changes to allow the Authority to define a GXP as non-conforming for the purposes of dispatch.
- This approach requires some changes to the SO's modelling tool, CSM. However, it has the advantage of removing the need to provide a feedback loop to the load forecast.

Option 1 Phase 2

In the absence of any information, if phase 2 is implemented as a separate project at a later date we have assumed that it will be a large project of a similar size to phase 1. This is because DD for conforming GXPs touches the same parts of the Market System as DD for non-conforming GXPs and will require similar amounts of testing.

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[21] Previously presented as variation A in the SO's April 2011 DD High Level Design Paper

[22] Purchaser bids have not always been accurate in the past. However, as there are compliance requirements associated with DD, we have assumed that purchasers will submit accurate bids.

It should also be noted that there is a trade-off between removing obligations from purchasers and minimising the scope and cost of change to the market system.

The option presented below is the scenario that would require the most changes to the market system:

- Purchasers at conforming GXPs can elect to be dispatchable or non-dispatchable and change this status up until gate closure.
- When non-dispatchable, their load is forecast by the central load forecast. The purchaser can submit a non-dispatchable difference bid for price discovery.
- When dispatchable, the purchaser must submit a dispatchable difference bid.
- There will be a requirement for the purchaser to provide metering at this node.
- Purchasers must be able to receive and respond to an electronic dispatch signal.

Key points:

- These purchasers will have their load forecast by the system operator's central load forecast unless they elect to be dispatched (off), in which case they will provide a difference bid that indicates the amount of MW that they are prepared to be dispatched off.
- However, simplifying the requirements for the purchasers has an impact on:
    - The load forecast
    - Final pricing (see below)
    - Bids (requires a new bid type).
    - Compliance (need to know the purchaser was complying with the load forecast before they dropped their load)
- The information used in final pricing will need to incorporate a MW dispatchable bid from purchasers. As the purchaser provides only a difference bid then the dispatchable bid will have to be derived from their separate market node metering and compliance of their ability to follow their dispatch instruction will need to be assessed.

It should be noted that purchasers at non-conforming nodes are unlikely to be ancillary service agents so do not have Genco terminals and allocated manpower already in place. For these purchasers the benefits of dispatchable demand will be offset by the additional compliance costs in this proposal.

7.1.6 Summary

These complexities have been highlighted in order to illustrate how complexity and therefore cost can be introduced if key design decisions are made without consulting with the SO first so that an impact assessment on the changes to the Market System can be made.

However, as the Code for phase 2 has not been developed, there is the opportunity for further discussion to continue between the SO and the Authority to explore the design and determine cost effective ways to handle DD at conforming GXPs. One possibility is to use the same mechanism as used in option 4.