Oakley Greenwood

The Impact of Late Rebidding on the Provision of Demand Response by Large Electricity Users in the NEM

prepared for:
Australian Energy Market Commission

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1.1. Background and purpose

In its consideration of the Bidding in Good Faith Rule Change that was proposed by the South Australian Government in December 2013 the AEMC recognised that rebidding may pose challenges for or reduce the value received by end-use customers that provide demand response into the wholesale market. In the simplest terms, when rebidding occurs it can change the financial returns realised from Demand Response (DR). Where rebidding reduces the financial returns from DR or makes it difficult for large end users to respond in a way that allows them to use their DR as they had planned, it may discourage both current and potential providers of DR.

In response, the AEMC engaged Oakley Greenwood to investigate the impact generator rebidding has on:

- large users in the NEM, and
- the incentives and returns to those users to engage in DR.

1.2. Approach

The assessment requested by the AEMC was undertaken through a combination of the following sources:

- the knowledge and experience of the OGW project team in DR issues and operations within the NEM and elsewhere,
- relevant secondary sources such as reports, presentations and articles, and individual consultations with 22 key organisations[1] representing a broad cross-section of stakeholders including DR aggregators and advisors, electricity retailers, individual firms that consume significant amounts of electricity, organisations that represent large energy users, electricity distribution businesses, and the Australian Energy Market Operator (AEMO).

1.3. Findings

Over-supply of generation capacity has depressed returns for DR

The present material over-supply of generation capacity in the NEM has resulted in historically low wholesale market spot prices, and a reduction in price volatility. The combination of these factors provides significantly less revenue over the course of a year to DR providers as compared to what had been available in the past.

Rebidding adds a new risk to DR and is very difficult to address with DR

However, all of the organisations that were consulted in this assignment mentioned that they have observed other departures in market price and market price movement in the present market as compared to previous times particularly in South Australia and Queensland. These include:

- significantly less correlation between supply/demand conditions and price than characterised the market previously;

1 Appendix A lists the organisations that were consulted.

- significant increases in spot price occurring at times they have not tended to occur in previous years;
- those periods of high price being quite short in duration as compared to previously, and
- those periods of significant price increase tending to occur in the last one or two 5-minute Dispatch Intervals of a given 30-minute Trading Interval.

Taken together, these factors have resulted – according to the organisations consulted – in it having become much harder to foresee and predict with any acceptable level of accuracy when a period of sufficiently high price to warrant the dispatch of DR is likely to occur.

Those interviewed agreed that the recent instances of late rebidding seem to be caused by base load generators who shift volumes (and sometimes prices) in their rebids. Other generators and sophisticated DR proponents can often see a pattern that precedes these rebids, which do not always succeed. They are most likely to succeed, however, when peaking plant is not running, and as a result, there are fewer generators who can react to put discipline on price.

Virtually all of the organisations consulted felt that these short durations of high spot price, which occur at times that would not be expected given general supply/demand conditions, are the product of bidding behaviour the purpose of which is to increase generator revenue in a market environment characterised by sub-standard returns. Organisations consulted differed markedly, however, on

- whether they saw this as price manipulation or rational economic market behaviour, and
- whether they felt anything should be done to limit such behaviour, and if so what sort of things should be done.

The impact of late rebidding on an end-use customer that provides DR within the NEM's 5-minute/30-minute price setting mechanism is different depending on whether the rebid occurs toward the beginning or the end of a 30-minute Trading Interval.

The figure below illustrates a late rebid that occurs in the last 5 minutes of a Trading Interval, as discussed in further detail below.

Assume a 1MW DR participant is monitoring prices and can immediately curtail their load on the appearance of a price spike. They will be expecting a price of $65/MW for the Trading Interval based on the observed prices in the first five 5-minute intervals. However, at the last 5 minute interval the price reaches $12,000/MWh and at that point the customer curtails their load.

Assuming that the 1MW load is the entire site load, then the customer has exposed its load to an average Trading Interval cost of $2,054.17/MWh for an average load of 833kW (i.e., 5/6ths of 1 MW) which equates to a total price of $855.90 for the half hour.

But it is also possible (in fact more likely) that customer needs 5 to 10 minutes to curtail that same 1MW of load. In that case they would miss the event entirely and therefore expose their full 1MW of load to the average price, and their cost for that half hour would be $1,027.08.

Rebidding is reducing the amount of DR that can operate effectively in the market

More generally, responding to these events limits the use of DR to those resources that can take action very quickly upon notification of a potential high price event and ramp down facility demand very quickly.

The aggregators and retailers that were consulted who are relatively active in working with customers to identify, arrange and deliver DR all reported that the only DR that can respond to these price events – and the only resources they are actively dispatching any more – are those that can deliver their target DR levels within 30 or preferably 10 minutes. One of these respondents reported that this has reduced the effective amount of DR available from his customers by 95%.

Even where customers can respond, the nature of these high price events makes them extremely risky to the end user as shown in the example above. Because these events are hard to predict, the choice is to either (a) dispatch DR whenever there is a chance of such an event in order to avoid the high price that is likely to last for one or two Dispatch Intervals but influence the price that will be applied to all electricity consumed by the customer in that Trading Interval, or (b) to only respond when the price event is definite.

The primary risk in the former situation is that the high price may not eventuate and any effort or loss in production experienced by the DR provider will have essentially been wasted. It is also the case this entails significantly more monitoring and, where the DR is dispatched in response to a notification from a retailer or an aggregator, there will be significantly more notifications than previously, which requires more attention from the end-use DR provider – but for less return. Some interviewees also reported that repeated requests to dispatch when the predicted high-priced event does not materialise and/or when one such event is missed (because it appears too late in the Trading Interval) causes frustration from within their company. The increased risk and transaction costs that were reported in some cases make the end-use customer reconsider offering DR at all.

The primary risk in the latter situation is that DR is not dispatched, and the party at risk (the customer if they are exposed to pool price, or the retailer in the case of a retailer program) is exposed to the spot price for the full load.

Rebidding is also problematic for peaking generators

It was also mentioned that late rebidding poses similar problems for peaking generators as it does for DR providers. Peakers need to be generating at times when the caps they sell will be called on, as it is the spot revenue that provides the funds for payments against the cap. Because the rebid high price events are hard to predict and have generally occurred at times when peakers do not typically generate, several peakers have 'missed' high price events, entailing significant financial payouts uncompensated by pool revenue. It was reported that in response, one peaker has reconfigured its plant to allow it to go to full load within a few minutes. This required a material capital expenditure and on-going costs to keep the generator spinning at a minimum level. However, the generator in question felt these costs were justified on commercial grounds including the avoidance of risk and increased flexibility of operation.

Actions taken by peakers to function in an environment of rebidding can be seen as the market correcting itself or as an exercise that adds costs without any additional market benefit

Some of those interviewed – generally retailers associated with generation businesses -- cited this as a self-correcting aspect of the market: one party finds a way to gain competitive advantage and another finds a way to counteract it. These respondents felt this was evidence that the market does not need intervention. They also expressed the view that interventions should be avoided wherever possible on the grounds that they often have unforeseen and distortionary effects.

Others, while recognising that such a response could mitigate the impact of the current instances of late rebidding, questioned whether such a solution was in the best long-term interests of consumers, as it will, of necessity, increase costs while providing no net benefit to consumers. Those respondents tended to see the current form of late rebidding as an abuse of market power[2]. Their view was that in these instances a generator was exploiting a temporal and in some cases a geographic position in which no other party can respond to the resulting price signal. These respondents felt that this was a product of the incumbency position of the causal generator in the bid stack and the technical limitations on other parties to respond. In short, they saw these events as 'cash grabs' rather than responses to supply/demand conditions.

Some form of gate closure was seen as a means of mitigating the problems associated with late rebidding behaviour, reinforcing the relationship between prices and supply/demand conditions and providing a better environment for the operation of DR.

In one of the interviews conducted early in the project the idea of an early gate closure was put forward as a possible 'fix' for the late rebidding problem. It was noted that there is no other energy-only market that operates without a gate closure mechanism, along with some sort of balancing mechanism to respond to supply/demand mismatches that arise after gate closure. It was recognised that the timing of the gate closure would be critical. For best results, the gate closure would need to be early enough to allow other generators and customers with DR capability to respond, but short enough to allow bids to be based on as good information as possible about supply/demand conditions and to limit the volume of adjustments needing to be handled in the balancing mechanism.

Several of the respondents – generally retailers associated with generation businesses -- were not in favour of any gate closure. They cited the self-correcting possibilities of the market and also (a) felt it is imperative that analysis be undertaken to determine whether the rebidding was actually producing any material disbenefit in the market before deciding there is a 'problem' that needs to be fixed, and (b) expressed concern that changing this basic aspect of the market could be costly and engender further distortions with more significant impacts than the original 'problem' caused by rebidding.

2 It should be noted that in economics there is a technical definition of market power. The definition generally includes reference to the ability of a firm (or firms) to manipulate the price of a good or service such that it is persistently and consistently above long-run marginal cost. The term as used by those interviewed may not have been meant in this technical sense, but was certainly used to reflect pricing that these respondents felt was both opportunistic and inappropriate (i.e., not in accordance with the intent of the market design or Rules).

All of the aggregators and large customer that provide DR that were interviewed and even one or two of the retailers felt that a gate closure anywhere from 30 minutes to 2 hours prior to the Trading Interval should be considered as a means for improving the ability of DR (and peaking generation) to make a positive contribution to the NEM. Most felt that 1 hour would provide the best compromise for providing a better basis for DR while avoiding undue volumes needing to be dealt with through a balancing mechanism[3].

3 It is worth noting in this regard that the Southwest Power Pool in the US introduced a 5 minute settlement with a 10 minute gate closure earlier this year. Early indications are that this appears to have negated the need for a balancing market. While this is a very interesting and potentially useful result, it should be noted that (a) it is an early result, and (b) it does not mean that this result would be experienced in other markets or that any gate closure interval longer than 10 minutes will necessarily require a balancing mechanism.

2. Background, purpose and approach

2.1. Background and purpose

On 17 December 2013, the South Australian Government submitted a Rule Change request to the Australian Energy Market Commission (AEMC) in relation to the bidding in good faith provisions contained in section 3.8.22A of the National Electricity Rules (rules).

The rules require that a generator makes all its bids and rebids in good faith such that, at the time of making the bid, the generator must have a genuine intention to honour that bid if the material conditions and circumstances upon which the bid is based remain unchanged.

The Rule Change request proposes changes to the good faith provisions that would require generators to demonstrate what material circumstances had changed as the basis for their rebid. In addition, the proposed rule would require generators to take into account all existing material circumstances when making a bid and, if there is a change to any of those material circumstances, to reflect those changes in rebids as soon as practicable.

The AEMC recognises that rebidding may pose challenges for or reduce the value received by end-use customers that provide DR into the wholesale market. In the simplest terms, when rebidding occurs it can change the financial returns realised from DR. Where rebidding reduces the financial returns from DR or makes it difficult for large end users to respond in a way that allows them to use their DR as they had planned, it may discourage both current and potential providers of DR.

As a result, the AEMC, as part of its assessment of this Rule Change request, engaged Oakley Greenwood to investigate the impact generator rebidding has on:

- large users in the NEM, and
- the incentives and returns to those users to engage in DR.

2.2. Overview of approach

The assessment requested by the AEMC was undertaken through a combination of the following sources:

- the knowledge and experience of the OGW project team in DR issues and operations within the NEM and elsewhere,
- relevant secondary sources such as reports, presentations and articles, and
- individual consultations with 22 key organisations[4] representing a broad cross-section of stakeholders including DR aggregators and advisors, electricity retailers, individual firms that consume significant amounts of electricity, organisations that represent large energy users, and electricity distribution businesses. We also consulted with the Australian Energy Market Operator (AEMO). While consultation with AEMO was not required by the scope of the project, it we seen as being valuable given the polarised opinions noted in the submissions to the proposed Rule Change.

The interviews were conducted in person wherever possible. Where a face-to-face interview was not possible due the need for interstate travel that could not be arranged, the interviews were undertaken over the phone.

4 Appendix A lists the organisations that were consulted.

A consistent approach was taken in conducting the interviews in order to ensure that the views of each stakeholder organisation were sought on all topics of interest. Those topics are shown in Table 1 below. The open-ended approach used in the interviews made for candid discussions and allowed the flow of the interview and the amount of follow-up undertaken on each topic to be adjusted to best suit the perspective and experience of the individual interviewee. It also allowed additional, related topics to surface. Where they did, those topics were then incorporated into subsequent interviews, as appropriate, to get input from other perspectives.

Table 1: Topics discussed with stakeholder organisations

1) The amount of DR currently made available in MW (i.e., the total capacity of DR that has been agreed to be exercised). To the extent possible, we also hope to be able to disaggregate that DR capability by state, and the sources of the DR itself, into the following categories:
   a) On-site dispatchable generation
      i) Synchronous
      ii) Break before make
   b) Temporary fuel switch
   c) Load cycling or temporary consumption reduction
   d) Load curtailment or rescheduling
2) The operational characteristics of that DR, including:
   a) the amount of notice required and how it is provided
   b) minimum ramp times required
   c) minimum, maximum and expected average dispatch duration per event
   d) number of events and total hours of dispatch expected or available annually
   e) how and when notification is provided regarding the amount of DR provided and compensation achieved in each event
   f) whether these parameters vary materially across the various sources of DR mentioned above
3) The nature of the commercial arrangements under which this DR is provided, including
   a) Whether it is through spot exposure on the part of the end user, or through an arrangement whereby a retailer or network business provides a payment
   b) At what spot price the DR is made available
   c) Whether the compensation provided for the DR is based only on dispatch or whether it is accompanied by an availability payment or option fee
   d) Opt-in/opt-out provisions, if any
4) The factors that are most important to end users when first considering whether or not to enter into DR arrangements
5) Whether late -rebidding (if it has occurred) has affected the amount and/or type of DR that is able to be deployed
6) Outcomes experienced in providing DR, in particular whether that experience has changed over time and how current DR conditions compare to previous years, with particular consideration of whether and to what extent generation over supply and late -rebidding have changed that experience.

2.3. Organisation of this report

Section 3 of this report provides the key findings of the study. Topics addressed include:

- The level of DR currently active in the NEM
- The specific end uses that provide the source of DR

- The decision criteria that large end-user consumers apply when considering whether to enter into arrangements to provide DR
- The operational requirements of DR provision
- The commercial arrangements that are (or have been) available for the provision of DR in the NEM, including the nature of the risks and rewards of the various available commercial arrangements
- The experience that large consumers who are currently providing DR and aggregators of DR (both retailers and third-party aggregators) have had in the past year or two with late rebidding, including the implications of these experiences for DR in the NEM.

3. DR in the NEM

3.1. Overview

DR for the purpose of this study is defined as a change made in electricity consumption by a large-volume consumer in response to real- (or near real-) time conditions in the electricity supply chain. Those conditions can be defined by:

- price (as in the case of wholesale market price, or a Critical Peak Demand network price), or
- operating conditions (such as the need to control frequency or relieve congestion in a local area of a distribution or transmission network).

The consumer may be directly exposed to a price signal – as in the case where the consumer has exposure to wholesale spot price, or where a network has a Critical Peak Demand – or may change consumption in response to a request from another party in the electricity supply chain. That request could be triggered by either a price signal or an operating condition affecting that party. This can include a network business' need to relieve congestion in a part of its network at a time of peak demand, a retailer's exposure to high pool price and/or its potential income from contract position settlement, or the market operator's need to control frequency fluctuations.

Table 2 provides an overview of the potential applications of DR in the electricity supply chain.

Table 2: Applications of DR in the NEM

DR application	Description	How implemented
Economic dispatch	Participation of DR in the energy market to reduce exposure to high spot prices	Customers can take exposure to pool price or participate in a program in which they reduce consumption upon notification from their retailer
Network support	Provision of a non-network means for managing constraints, reducing load at risk, deferring capex augmentation requirements, or providing voltage support	Actively supported by recent regulatory requirements and incentives applicable to network businesses, including the RTT-T and RIT-D, STPIS, DMEGIS, and the requirement to develop and implement DM engagement plans
Frequency control	Curtailing load to restore frequency	Can only be provided through a retailer
Frequency keeping	Monitoring the system frequency and curtailing and restoring load to increase or decrease load respectively to maintain a predetermined frequency setting	Can only be provided through a retailer
Reserve capacity	Capacity in excess of demand in case of a supply side shortage	Reliability and Emergency Reserve Trader (RERT)

3.2. Level of DR currently active in the market

Of the applications of DR listed in Table 2 above, it is only economic dispatch that is likely to be affected by late rebidding. This is the case because it is the only application of DR in which wholesale spot price serves as the price signal.

The amount of DR that is currently being exercised for the purpose of economic dispatch is difficult to assess for a number of reasons[5], including the following:

- Not all of the available DR may be exercised in response to any single price event – The customer's ability and/or willingness to provide DR on any particular occasion will depend on a number of factors in addition to the price being offered. The factors include their production requirements and commitments at the time, and the flexibility of their production and ancillary processes. As a result, DR at the level of an individual customer generally needs to be seen as a probable rather than a firm resource. The response of an individual customer could be, at worst, binary, in fact (a) some customers can provide a variable amount of DR, meaning that it is not all or nothing, and (b) as the number of potential providers of DR increases, there is likely to be a proportion of that aggregate potential that is likely to be available on any particular event characterised by a specific wholesale market price level. This can allow DR on an aggregated basis to have a level of essentially firm response (defined as a decimal fraction of aggregate 'nameplate' DR capacity)[6].
- Disclosure of this information provides no commercial advantage for (and can pose at least some risk of commercial disadvantage to) parties seeking to exercise DR as a means for responding to wholesale market price movements.

AEMO has estimated the amount of DR that is active in the wholesale market of the NEM through two approaches[7]:

- Analysis of half-hourly metered data for large industrial loads from January 2000 to March 2014 – The analysis identified those periods when the regional wholesale price exceeded specific price levels (i.e., $300/MWh, $500/MWh, $1,000/MWh, and $7,500/MWh). DR was estimated by calculating the difference between the customer's observed demand in the hours where these threshold prices pertained and the customer's average daytime demand[8] for the same day.
- The results of surveys undertaken in 2013 and 2011 with network companies, retailers and DSP aggregators – These surveys provided an estimate of the level of demand-side participation available and being delivered by smaller customers.

The estimates obtained from both segments were combined to provide estimates of the amount of DR available in each NEM region, by season, as shown in Figure 1 and Figure 2 below.

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5 Identifying the amount of DR contracted for network support in the NEM is significantly easier, by contrast, because it is generally available in reports published by network businesses.

6 Where a specific target level of DR is needed (as in the case of DR for deferral of network augmentation) an amount equal to about 110% to 115% of the requirement will generally be contracted to allow for non- or under-performance at individual sites. This rises to about 150% where the DR resource must be available for prolonged periods and/or dispatched over several consecutive days.

7 See Chapter 7 of AEMO's *Forecasting Methodology Information Paper, National Energy Forecasting Report 2014*, July 2014, for further detail on AEMO's assessment of the amount of DR currently available in the NEM.

8 Daytime demand is defined as occurring being between 7:00 AM and 8:00 PM and includes only those hours in which spot price is below $300/MWh. Overnight hours are excluded from the analysis because it is possible that some customers might have increased demand then in response to the availability of lower overnight prices. Where that is the case, inclusion of overnight demand levels would result in an under-estimate of the level of demand response being provided by those customers.

Figure 1: Estimated MW of DR available in Winter 2014, by region and spot price

Estimated available DSP - Winter 2014					
	QLD	NSW	VIC	SA	TAS
Prices > $300/MWh	49	18	45	39	0
Prices > $500/MWh	49	22	57	41	5
Prices > $1000/MWh	51	24	63	43	5
Prices > $7500/MWh	61	80	140	126	37
Prices = MPC	123	214	262	147	56

Source: AEMO

Figure 2: Estimated MW of DR available in Summer 2014-15, by region and spot price

Estimated available DSP - Summer 2014-15					
	QLD	NSW	VIC	SA	TAS
Prices > $300/MWh	49	18	65	39	0
Prices > $500/MWh	49	22	77	41	5
Prices > $1000/MWh	51	24	83	43	5
Prices > $7500/MWh	61	85	214	126	37
Prices = MPC	123	219	336	147	56

Source: AEMO

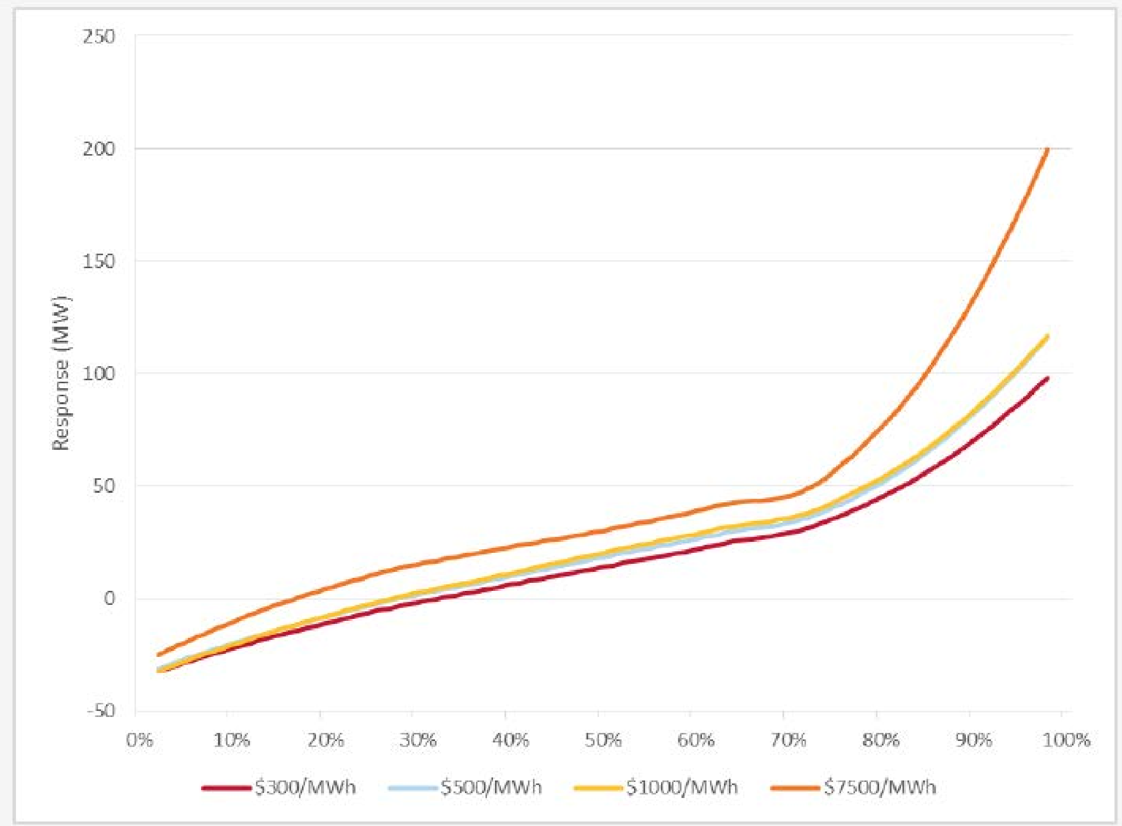
Based on its analysis, AEMO advised that the Summer seasonal estimate should be applied to the months of December through March only, and the Winter seasonal estimate should be considered applicable to all other months.

The number of high-price events enabled AEMO to make what it felt was a reasonable estimate of the probability distribution of the amount of DR that can be expected at different wholesale market prices. Figure 3 below provides an example of such a probability distribution, in this case for NSW. AEMO notes that this graph indicates that

- 90% of the time when prices have been at or above $1,000/MWh, the historically observed level of DR has been at most 80 MW. In other words AEMO observed that when these high-priced events appeared, demand dropped by 80MW which suggests that this was DR responding to the high price, and
- DR from large industrial loads is a probable resource rather than a firm resource; the MW provided at any of the four price levels varies substantially based on the applicable price level in any specific event, with quite high prices being required to induce materially incremental levels of DR[9].

9 AEMO, *Forecasting Methodology Information Paper, National Energy Forecasting Report 2014*, July 2014, p 46-47.

Figure 3: Probable level of DR in NSW at different wholesale market prices



Source: AEMO

Despite this variation, AEMO notes that the lowest ***expected*** response on any of the individual price lines occurs in 10% POE conditions (which occur at the 90% point on the x axis in the graph above) and the highest expected response occurs (in practical terms) under 2% POE conditions (which occur at the 98% point on the x axis), with the expected response in 50% POE conditions occurring at the 94% point on the x axis.

Based on these comments, DR in NSW would be expected to be somewhere between 60MW and 200MW depending on the wholesale price pertaining at the time and the POE of the year in question.

It should be recognised, however, that while AEMO's estimate is based on observable reductions in demand at the onset of these high-priced events, it cannot be certain that these responses are entirely due to DR.

3.3. Sources of DR

DR is defined as any conscious action undertaken by a customer to reduce their demand in "response" to a signal to do so. Such DR can be provided in a number of non-mutually exclusive ways including:

- The use of an on-site generator to offset mains electricity consumption. The generator may be configured synchronously with the grid, in which case, the facility can start the generator while still drawing mains power, or in a break-before-make mode, in which case the facility needs to cease drawing mains power prior to connecting and using the generator.

On-site generators are almost always present in hospitals, and often found in other essential service and other facilities as well. Data Centres and telephone exchanges almost always have Uninterruptable Power Supplies (UPS) that can be used to power their operations for up to 15 minutes as well as diesel back-up generators with double and at times triple redundancy and a minimum of three-day supply of fuel.

- The ability to substitute the use of another fuel for the use of electricity on a temporary basis, as in the case of a dual-fuel boiler. For example, glass manufacturers and smelters can often substitute the use of gas for electricity (or vice versa) to maintain heat in their manufacturing processes.
- Load cycling or temporary consumption reduction. For example, a cool store may have a large cooled area with several tons of cold material that will hold its temperature for some time. In such cases, active cooling can be switched off for a time (generally for anywhere from 1 to 4 hours depending on the specifics of the cool store and the material in it) without negatively impacting on the quality of the cooled goods.
- Load curtailment, re-scheduling of load or siphoning of a storage facility. Where the price offered for DR (or the savings against pool price) warrant, parts of a production line can be progressively curtailed. Cement mills and paper mills typically provide DR this way, using the down-time to undertake maintenance with idled employees shifted to other work during the period.

The choices made by DR providers as to what sources of DR they will use are dictated in large measure by the nature of the end user's equipment and the production processes of the facility. As noted in the following section, however, most businesses are reluctant to make major changes to their equipment or processes specifically to enable DR unless those changes also provide some additional benefit in their production efficiency or control, or the DR program can provide realisable benefits with certainty and within a reasonable timeframe. As a result, most Economic Dispatch DR in the NEM[10] is provided through means that are relatively easy for the facility to put in place without significant additional capital or operating expense[11].

Unfortunately, there are no reliable estimates of the relative use of the various strategies by the large end users that provide DR in the NEM. A breakdown is available from New Zealand, however, where EnerNOC uses DR in the frequency control market. While the use of DR is quite different in that application as compared to its application in a wholesale energy market, the breakdown of the 200MW of DR[12] that EnerNOC has under contract there from 86 customers[13] provides at least some guidance as to the relative availability of DR from different sources:

- 163 MW (81.5%) comes from time shifting of certain operations, with no overall loss of production and at only minimal cost to the business,

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10 In other electricity markets and with other uses of DR where availability fees are provided, end users can and do invest in DR source improvements.

11 Where initial experiences in providing DR are positive, customers will in many cases investigate additional means for providing DR, which may involve more intervention and coordination of production processes and/or some capital investment, which often includes aspects that improve production control.

12 Equivalent to about 2% of the installed generation capacity in New Zealand and about 3% of New Zealand peak demand.

13 EnerNOC, *Submission on consultation paper on cost-benefit assessment of the DRM*, 12 August 2014.

- 17 MW (8.5%) involves some production loss, and almost all comes from a handful of large, heavy industry sites, where some of the processes that are interrupted would otherwise run essentially continuously, and
- 20 MW (10.0%) comes from standby generators that were already in place in these facilities, meaning that the only expense is the input fuel (generally diesel) to run the generator.

It should be noted that in ancillary services markets, such as for frequency control, DR providers must be able to reduce load within a very short time (generally from 1 second to no more than a minute or two) but will only be required to maintain that reduction for relatively short periods (generally less than 15 minutes). Curtailable loads of the types available in cool stores, air conditioning, compressors, mills, smelters and many other types of loads are optimal for these applications. By contrast, the usefulness of on-site generation is limited in such applications to those that are fully synchronised with the electricity grid and that can start almost instantly (which will generally require that the generator is at least running – and therefore using some fuel -- even before the notification, or for an Uninterruptable Power Supply (UPS) to coexist with the generator).

Network DR programs, in which notification can generally be provided the day before it is needed and DR events can last for a number of hours (and sometimes be required on consecutive days), are the other extreme. In these applications, DR provided by on-site generation is optimal although curtailment of large loads in facilities such as cement mills, steel mills and quarry/mining operations are also often suitable.

The use of DR in the NEM's wholesale electricity market (for Economic Dispatch) sits between these extremes in terms of the notice that is generally available. Historically, high price events have most often been associated with very high demand caused by several consecutive days of very high temperature. This allowed retailers and large end users to at least be on alert for potential applications of DR. But even in such situations, firm notification calls are seldom issued by retailers on a day-ahead basis due to the risk of abrupt changes in weather leading to lower prices. Rather, notification tends to be provided no more four hours in advance of an anticipated high-price event.

All of the DR aggregators and retailers that are currently using DR in the wholesale market that were interviewed for this project stated that, under current conditions, notice cannot be made more than 30 minutes in advance and that shorter periods are much preferred. The main determinants of these conditions were cited as being (a) the significant level of over-supply that currently characterises the wholesale market, and (b) the incidence of late rebidding. Under these conditions, the types of DR reported as being useful were quite limited and included only (a) curtailable loads that can ramp down very quickly, such as pumping loads and other DR sources which can be curtailed quickly and preferably remotely, and, to a lesser extent, (b) fast-start (synchronised) on-site generation.

3.4. End user decision criteria regarding DR

The decision-making process and criteria that large energy-users apply when considering participation in a DR program include the following:

- *Awareness* – In our experience many large customers – even relatively technically sophisticated ones – are not particularly aware of what loads they could curtail or what value they could extract from that curtailment. This view was corroborated by the DR aggregators, retailers and customer representative organisations that we consulted with. Several retailers reported that in general customers are not interested in the prospect of taking pool price exposure or being asked to reduce their consumption. Both of the representatives of customer organisations we consulted with mentioned that awareness of the potential to use DR to reduce electricity costs is surprisingly low among their members. Retailers and aggregators confirmed our experience that when first approached to consider DR, most large customers state that there is nothing they can turn off. For retailers, whose primary function is to win customers and sell electricity, this generally functions to focus the retailer on other ways in which the retailer's offerings can be made as attractive as possible to the customer. This may be changing somewhat as electricity and gas prices increase, and information on the role DR can play in assisting customers in saving money and putting downward pressure on electricity prices has become more widely discussed in the media[14]. One retailer reported that in their experience, the combination of very thin retail margins for commercial and industrial load, and increased interest in electricity cost control within that market segment, is making participation in DR and the provision of other energy management services significantly more important to the retailer than previously for customer acquisition and retention purposes. This particular retailer – one of the three largest in Australia -- has embarked on an initiative to engage DR aggregators to prospect and manage DR resources on the company's behalf – but also reported that network applications offered the best prospect for DR under today's market conditions.
- *Operational concerns* – Potential DR providers are also concerned about the potential for participation in DR to pose a risk of interrupting production processes, or damaging production equipment or quality. Where on-site generators are used, potential DR providers are concerned that the generator may fail and/or the switch back to the grid may not happen smoothly. Those that curtail discretionary loads generally have the least concerns; however, such loads are often limited depending on production schedules and resource scheduling, including what to do with staff who have been idled by equipment and processes being shut down for the period.
- *Managerial bandwidth* - Even large customers have limits to their management time and engineering resources. Where the feasibility of DR provision or management of the resource requires significant analysis or involvement of corporate or production managers, returns will need to be significantly higher and more predictable in order for a proposal to provide DR to get up.

14 The cost of energy may or may not be a significant cost input but almost certainly it can affect the competitiveness of the company. For companies that participate in spot exposure energy savings effectively reduce their energy costs whereas companies that participate in retailer and aggregator DR programs in which they earn an income from DR that income goes directly to the company's bottom line profit.

- *Technical risk/reward considerations* – While DR offers financial benefit to the firm, technical responsibility for its operation and any risk that the operation of DR poses to the main line of business of the firm generally rest with a plant or facility manager or engineer. In some cases, such as hospitals, the engineering departments who provide the DR do not get their budgets credited with the revenue earned from the DR they provide, so the risks and rewards of the DR are not aligned, which often poses a barrier. Where customers offer DR via an aggregator or retailer, they are generally shielded from market price risk, in exchange for which they must share the rewards with the aggregator. The customer would still be exposed to any technical risk associated with the provision of its DR, however.
- *Materiality and certainty of the returns* – Before a final decision is made on whether to enter into an arrangement for the provision of DR, end users will seek to understand the size and certainty of the revenue to be expected. Ideally, end users will want to be relatively certain that they will receive a level of revenue that justifies the amount of management attention, direct cost, lost production, other operational costs and inconvenience incurred to provide the DR. The level and certainty of the revenue will depend on a host of factors including the number and duration of pool price periods that are expected to meet or exceed the customer's dispatch price trigger (including any rebidding by generators), and the specifics of the commercial arrangements through which they provide their DR, and the dispatch decisions of the retailer or retailer agent (in the event that the customer is not taking direct exposure to pool price), It is also the case that customers may offer DR without a full understanding of the variability of all these factors. Where expectations are not met because of such variations, DR that had been offered may be withdrawn.
- *Market information monitoring requirements* – Being exposed to the spot price requires an understanding of the market and associated risks as well as the means by which customers can track price events and, insofar as possible, predict them. These systems are expensive and complex, but necessary in order to provide the risk management that is required. In such cases, the aggregator or the retailer takes on the price risk when that DR is dispatched in the wholesale market. Aggregators (to a significantly greater degree than retailers) invest heavily in near real-time technologies in order to relieve the end-use customer from this responsibility and risk, and to monitor and control their aggregated DR in those cases where they have undertaken to provide a specific amount of DR (which is often the case where DR is being used to provide network capacity support, in which case the aggregator takes on performance risk).

As a result of all these factors, the DR that is provided – particularly the DR that is initially offered by an individual customer – will generally be comprised of the simplest and easiest opportunities available within the facility. Where rewards have met expectations, and responding to the price signal or retailer call is not overly burdensome and where additional opportunities exist, customers may decide to make investments to increase the amount of DR they can provide, with an expectation that exercise of the DR will be frequent and remunerative enough to recoup and earn a return on any incremental investment required to provide that DR.

3.5. DR operational requirements

In our experience the operational parameters that are of most importance to potential providers of DR and that most differentiate the types of DR are the following:

- notification time required;
- ramp time required;
- times of year the DR is expected to be available;
- minimum event duration and expected average and maximum event duration;

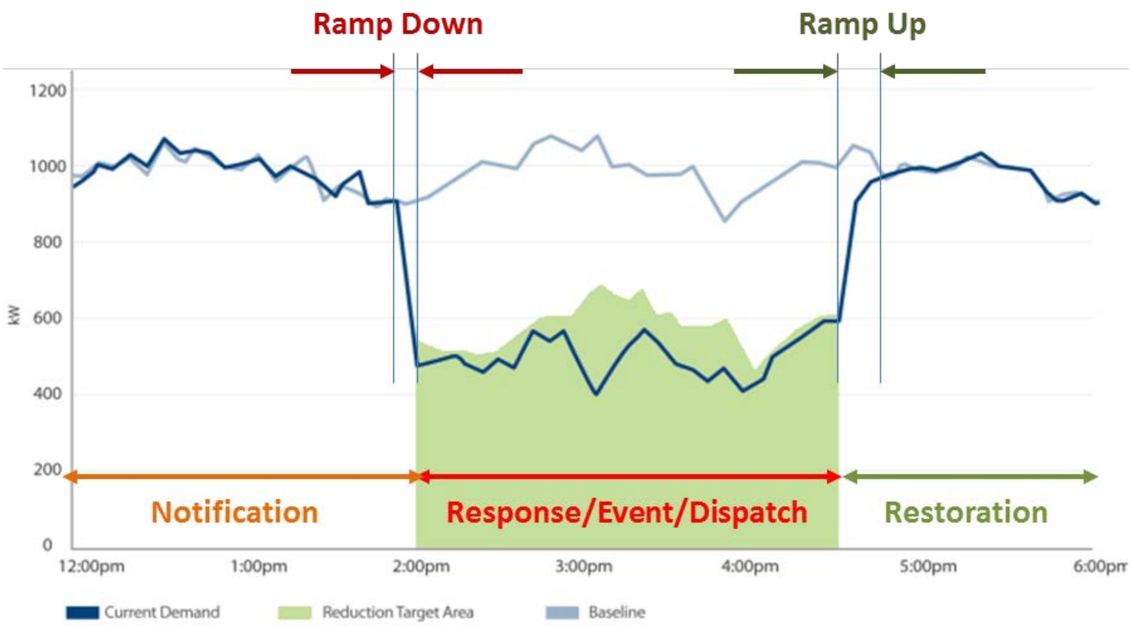
- total hours of expected DR provision per year or season;
- potential for consecutive days of events; and
- telemetry requirements, including timeliness of data from all sites during a DR event.

It is worth noting that the most important operational parameters are not always those that were considered in the original decision to provide DR. For example, at customer workshops organised by Energy Response following the completion major DR programs, customers have been asked to discuss what they had learned, what benefits they saw (other than payments), what issues they encountered and whether they would participate in future events. Issues that have been mentioned in response often relate to ramp-down and ramp-up times/requirements which are critical to regaining quality production, the risk of non-restart of equipment/machinery/product line, loss of production, etc. Participants have generally reported being satisfied with their experiences in the DR programs they have taken part in, with many reporting that they have also found ways to improve their energy efficiency and energy utilisation.

While it is not strictly an operational parameter, the baseline methodology used to determine the amount of DR provided can be very important to the DR provider (and the overall success of the DR program). Development of an approach needs to (a) recognise that the 'without DR' (i.e., baseline) consumption of the facility may vary from day to day, and (b) develop a fit-for-purpose methodology in light of that which balances the need for accuracy with the cost of doing so.

Figure 4 below provides a notional timeline of the operational phases of a DR event. The paragraphs following the figure provide more information on those operational phases.

Figure 4: Operational phases of a DR event



Notification

This is the advance warning that is provided to the customer in which time they make preparations to curtail their load. A decision is made to call for DR (this can be done by either a retailer, an aggregator, or by the in-house group charged with price monitoring in the case of an end user taking pool price exposure. The notification may include a request for a specific amount of DR, or a request that the DR provider specify the amount of DR to be provided.

In some situations the customer may need very little time (like the time it takes to flick a switch), at other times the curtailment process can be automated to react on a signal (like a high price signal) or a generator may need to be started manually and switched over to take on the load, or the generator may be able to start automatically and take the load instantly, and every other possible permutation in between.

For some types of loads, curtailment can happen instantly, for others it may require a few minutes to a few hours – and some need a day ahead notification to dispatch (particularly hospitals and other essential service providers).

Table 3 below provides a rule of thumb regarding the proportion of available DR that can be expected to occur under varying notification timings, and the relative firmness or confidence in achieving that quantify of DR.

Table 3: Approximate effect of notice period on the realisable proportion of available DR

Notice Period	Likely realisable proportion of dispatchable DR	Relative confidence in Firmness of the DR provided
Day-Ahead	100%	High
4 Hours	80%	High
2 Hours	75%	High
1 Hour	60%	Medium
30 Minutes	40%	Low to Medium
10 Minutes	20%	Low
1 Minute	<10%	Very Low

Source: OGW project team experience

Communications with the customer

Generally the intermediary (i.e., the aggregator, retailer or network that is operating the portfolio of DR) uses multiple communication means so that if one form fails another may still get through. The most common forms of communication with the customer for Notifications are telephone, mobile (voice or text), email and fax. Once alerted to an impending Event, the customer normally confirms their plant's availability via the same communication media. Where a customer fails to confirm their readiness to Dispatch (within a reasonable period of time[15]), the intermediary will generally try a secondary communication. If that remains unanswered the aggregator will assume the end user is not participating, but will follow-up after the event to ensure that the communications channels are operating and that the end-use customer understands that responses to notifications are a requirement of the program.

15 Note that to react to a 5 minute dispatch notification as would be necessary in the NEM there is no time for a confirmation from the customer that they are willing to dispatch their plant and there is very little time for Ramp Down.

Where remote or automated means are possible these signals are usually carried by the telephone or mobile network, however some networks in particular use radio and ripple control (a powerline carrier technology).

System Operators and Market Operators generally have only large loads and/or aggregated loads. As a result they will typically be dealing with only a handful if customers and/or intermediaries. Their communications requirements are relatively simple and in most cases (in Australia) they use the telephone and/or mobile to call for DR.

There is generally little communication with the customer during the Event but prior to Restoration the intermediary will again contact the customer via the same communications medium as before and seek a confirmation that they will Restore.

DR decision

Once the customer gets the notification call (whether that comes from the retailer/aggregator or the in-house price monitoring group), a decision will need to be made as to whether to respond to the notification; that is, whether or not to dispatch DR and how much. Note that the final decision is generally made by the production group within the customer facility.

One retailer noted that the Dispatch can always be cancelled during the Notification period, however they also noted that they are hesitant to notify their DR customers unnecessarily, and therefore as a policy do not send notification unless they are quite certain of the Event, and generally do not cancel notifications except in extreme situations.

Ramp down

Once the decision has been made to dispatch DR, specific actions will need to be taken. This can be as simple as flipping a switch, but it could involve much more effort – for example, notifying plant operators to change machine operations. These activities will be specific to the end-use equipment and production processes within the facility. The most complicated curtailment actions are winding down a continuous production line (like a chemical or petroleum refinery) and break-before-make generators[16].

Once those actions are taken, the load can begin to change (i.e., the load can begin to curtail). Again, how fast the load can be ramped down and DR provided will be specific to the end-use equipment and production processes within the facility.

Response/Event/Dispatch

This begins once the load has ramped down to the level that has been decided for the particular event (or to some pre-selected target). The DR is provided for the duration agreed and in the amount agreed in the DR decision.

Few loads have an entirely flat profile – even when curtailed (unless the entire site has been switched off or switched over to an on-site generator).

Different DR purchasers will have different ways of calculating the baseline and current demand profile. There is no standard or internationally recognised measurement method for DR.

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16 In a commercial building with break-before-make generation an operator/electrician will need to be called. They will check the generator/s and fuel level and start the generator. Once started and at speed the operator then calls all the lifts to a convenient floor where the doors are forced open. Where possible loads are then minimised by switching off lights, fans and other non-essential loads. Only then will the operator switch the site load (partly or wholly) off the grid and across to the on-site generation. The Restoration process is the same but the load is switched back to the grid once it is off loaded from the on-site generation.

Curtailable load is normally used for relatively short durations (from a few minutes to about 2 hours) and on-site generation is preferred when a Dispatch period must continue in excess of 2 hours at a time.

(Near) Real-time monitoring

While real-time monitoring is not essential for all Events, it is very useful and reduces operational and market risks. It is usually activated by taking the pulse output from the utility billing meter[17]. The Meter Data Agent must be called upon to route the pulse output from the meter's internal circuits to an external terminal block, from which another technology provider (usually the aggregator) will take the pulses and aggregate them into 1 or 5 minute readings of kW/kWh. These signals are then relayed back to the aggregator's operation centre where each site's Dispatch performance is closely monitored.

Restoration or ramp up

Load is ramped back up to the level desired by the production group at the time previously agreed with the party that placed the notification call, or in communication with the aggregator or retailer, or upon receipt of further information from the in-house price monitoring group).

This step can pose difficulties. For example, a problem often experience by manufacturing facilities is a loss of product quality during the ramping periods and in some extreme situations this may lead a prolonged period of adjusting the quality of the product being manufactured during and after the ramp up period (i.e., during Restoration).

Another problem frequently experienced in ramp up is the possibility of overshoot. This is where the current drawn by the load switching back on overshoots the baseline. In some extreme cases this can cause the maximum demand of the plant to be affected, thereby resulting in increased network charges for the following 12 months.

Normally the customer providing DR is not compensated for ramping or loss of product quality or increased network changes. These are technical risks for the end-use customer to manage, though aggregators will generally make their DR providers aware of the potential for these problems and provide assistance where they can.

Financial settlement

Financial settlement requires two key inputs: (a) the amount of DR provided, which might come from the meter of an on-site generator, a deemed value, or through comparison of the metered output of the process or the facility with a baseline energy consumption trace and (b) the price to be paid, which may be a deemed value or a percentage of the pool price during the event. Note that this step is not needed in the case of a customer that is taking exposure to the pool price, as they will simply pay for the electricity they did consume at the pool price.

Because it is unlikely that the customer will know the quantity of DR they have provided, it is generally the responsibility of the intermediary to make this determination and tell the customer. This means that the intermediary must be able to access the customer's (utility) meter data for the event period in order to calculate the DR that was provided.

17 An electronic billing meter will produce a pulse output usually every 1 to 3 seconds, these are aggregated within the meter's accumulator and then registered at regular intervals which are normally 15 or 30 or 60 minutes.

The intermediary will then provide a statement to the customer of what they have earned from the DR activities for the month or quarter. On payment to the customer the intermediary will generate a Recipient Created Tax Invoice (RCTI) or, in the case of a retailer, they may simply credit the customer's electricity account.

3.6. Commercial arrangements available for DR in the NEM

3.6.1. Available commercial arrangements for DR

There are several ways large electricity users can provide DR into the wholesale market of the NEM for Economic Dispatch. They include:

- The customer can take full pool exposure as a wholesale market customer;
- The customer can take either full or partial exposure to the spot price through an electricity retailer[18];
- The customer can participate in a retailer DR program in which the customer receives either:
  - an arbitrage payment – generally a percentage of the difference between the spot price and the applicable price in the customer's retail electricity contract - when they reduce their electricity consumption in response to a request from the retailer; or
  - an availability payment or an option fee in exchange for their agreement to provide a target amount of DR (generally on a best endeavours basis) when asked to do so by their retailer, or
  - a lower electricity price from their retailer in exchange for their agreement to provide a target amount of DR (generally on a best endeavours basis) when asked to do so by their retailer[19].

Of these, participation in a retailer program or taking partial pool price exposure through a retailer are the most common arrangements used by large electricity customers as the basis for providing DR into the NEM's wholesale market. Only three end-use customers in the history of the NEM have taken full pool price exposure as wholesale market customers, and only one customer based in South Australia is doing so at present.

Where the DR is offered via an aggregator or retailer the market risk is absorbed by the aggregator/retailer who manages that risk while the end user must accept operational risk. The end user knows their plant and the dynamics of that plant, so the operational risk is more easily managed by the user. The utility client who is purchasing the DR also has a risk to manage – the network and market operator alike must ensure secure and reliable power supply continues to flow, while the retailer (where they are the client) has a financial and trading risk to manage.

18 The customer can take full pool price pass through from a retailer or enter into a retail arrangement under which they receive all their electricity requirements below a certain price or level of demand at a contract price and take full exposure to spot for load above that level.

19 Much less frequently a retailer may offer to provide funding an investment in a customer's standby, emergency generation or co/trigeneration assets to enable their use for demand reduction. This will generally only be done where the customer has committed to a relatively extended contract with the retailer.

Where an aggregator or retailer contracts for the provision of DR with a network company for network capacity support, or a market/system operator for frequency or voltage control or reserve capacity, the key commercial elements between these parties must be reflected in the agreement between end users and aggregator. For example, if the client (i.e., the network operator or the market/system operator) wants a relatively short notification period of (say) 30 minutes then the aggregator/retailer must impose that condition on the end user and seek out fast start standby generators or curtailable loads that can react in that time frame. The aggregator/retailer will provide price certainty for the customer and remove the need for the customer to know anything about the electricity market, trading, hedges, price spiking, or anything else of any industry complexity.

Aggregators will often be required to provide security deposits and/or performance guarantees (and associated penalties for non-performance) to networks and market operators that cannot, in a practical commercial sense, be passed on to the end-use customers that provide DR. In such cases, the aggregators will use technology (real time monitoring, advanced communications to support immediate customer contact, forecasting and predictive applications, etc.) and a portfolio of DR sources including over-contracting of DR capacity to minimise the performance risk. These risk mitigating actions are costly, and justify the aggregator's commercial returns (usually between 40% to 60% in gross margin terms per program[20] depending on the risk profile and the extent of the mitigating actions).

Aggregators in particular also provide a technological interface to the System and Network Operator such that secure communications can be established and certainty achieved in dispatching the contracted DR. Aggregators often provide portal access to these types of clients so that they can monitor the dispatch of DR in real-time just as the aggregator does. This can be very useful particularly to market/system operators whose SCADA systems usually have relatively low resolution and therefore may not be able to distinguish the curtailment of a few tens to a 100 or so MW on their grids.

No such commercial arrangements are required when an end user exposes their load to the spot price. A retailer who manages that customer's load may well provide market price and other information, and assist the customer by purchasing hedges to better manage their risk. Generally, however, the customer is left to their own devices. This is a barrier to more customers participating directly in the pool or with pool exposure as it requires a high level of understanding of how the market operates. However, feedback gained in the interviews conducted with large energy users that provide DR suggests that such participation is well worth the effort, particularly if the customer has good capabilities in short-term price forecasting, as this is a critical success factor in managing the risk inherent in spot price exposure.

3.6.2. Nature of the risks and rewards of the different commercial arrangements

The arrangements listed above differ in how the end-use customer experiences the benefit of DR. In the case of full or partial pool exposure, the customer reduces the amount of electricity they consume at times when the wholesale price of that electricity exceeds the value to the customer of the use of that electricity. This arrangement is generally taken up by the customer because they believe they can manage their consumption sufficiently to result in lower overall electricity costs on a seasonal or annual basis than they would incur by either (a) taking an all-requirements retail electricity contract in which the electricity price would include the cost of financial hedges to protect the retailer from the customer's consumption volume at times of high price, or (b) purchasing those financial hedges itself.

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20 That is, total revenue minus payments to its DR providers.

In the case where the customer receives a lower retail electricity contract price in exchange for their agreement to provide DR upon request from the retailer, the customer often benefits with no further action. This is the case for a combination of two reasons: (a) the retailer may not make a call for DR over an extended period of time, and (b) the customer is generally not required to respond as these arrangements generally only specify that participating customers offer their DR on a 'best endeavours' basis[21]'. As a result, the difference between pool exposure and this sort of lower electricity price arrangement is that in the former case the customer must act to manage their overall electricity costs in order to achieve meaningful benefits from the arrangement, while in the latter case, the customer may not need to act at all in order to benefit.

By contrast, in retailer programs that offer either an arbitrage payment, or an availability price or option fee, the customer actually pays their electricity bill as they normally would, but receives an actual payment from the retailer. The difference is that these arrangements provide an income stream (in the case of arbitrage or availability payments) to the customer providing the DR, whereas those discussed above serve to reduce the customer's bill – either all the time (in the case where the customer gets a lower retail electricity price from the retailer), or from time to time (in the case where the customer has pool price exposure and reduces consumption at times of high spot price).

Correspondingly, the different arrangements put different risks on different parties. Under either of the arrangements that involve the customer taking exposure to pool price, the customer faces both volume and price risk – as their electricity bill outcome is a product of the specific level of the pool price and the level of electricity consumed by the customer at that price. In the case of a retailer arbitrage program, the retailer generally mitigates the customer's price risk by guaranteeing a minimum $/MWh price to be paid for the DR. In general, customers do not participate where that minimum is not an amount that they would, in most cases, be prepared to accept in return for reducing their consumption. In this sense, the customer retains volume risk, in that the customer's pay-off from DR under this arrangement is related to the amount of load reduction. It should be noted, however, that in almost all of these programs, there is no penalty to the customer for not reducing demand in response to a call from the retailer. As a result, the risk to the customer is only a risk of not getting as much benefit as they might have – they will always get some payment if they reduce their consumption, and they have no risk of losing money[22].

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21 It is worth noting that in most formal DR programs the customer will be exposed to soft penalties. For example they may be contracted to provide 1 MW and be paid an availability fee accordingly. When asked to dispatch, the customer may only provide 0.5MW, in which case the availability payment may be adjusted to reflect that lower level of DR provision until such time the DR is retested and found to be at another level (either higher or lower). Where a customer fails to provide DR the aggregator or retailer will often have a discussion with that customer to discover the cause of their failure. Where the customer materially and repeatedly fails to provide the amount of duration of DR initially offered, the customer will often be advised that they are at risk of losing their DR contract, and at some point they will most likely be excluded from the arrangement.

22 The only exception to this is in the case where a customer has incurred costs to make themselves capable of reducing consumption in response to a call from the retailer. In such a case, the customer may not recoup those costs where the payments received are lower than expected or less frequent, or both.

By contrast, the retailer offering the program retains price risk, as pool price could change after the retailer calls for DR and winds up being lower than the minimum guaranteed to the customer. The retailer also takes on risk in the programs where a lower electricity price or an availability payment is offered. In the event that DR is not needed (i.e., the price never gets to a level in which the retailer calls for the customer to provide DR) the retailer will have paid money or reduced revenue for 'no reason'. However, this is similar to the costs that retailers routinely incur for financial hedge products – and cap contracts in particular. The difference is that in order to function equivalently to a cap contract, DR must be firm – that is, it must come forward in the amount contracted whenever needed so as to replace the need for a cap. In the event that the DR offered in these programs is not delivered when called, the retailer will have both volume and price risk.

Because the retailer incurs costs in arranging and administering the program – and particularly because the retailer retains material price and volume risk – it usually seeks to retain a material percentage of the benefit available from the DR anticipated to be provided under these arrangements.

3.6.3. Existing DR potential not being realised and future opportunities for DR in the NEM

As noted in section 3.2 above, a material amount of DR has already been observed in the whole-sale market. However, there may be significantly more DR available in two broad categories, as discussed below.

DR already involved in a DR arrangement but not necessarily dispatched in any particular high-price event

It is quite likely that there is more DR under contract – and ready and willing to participate in the wholesale market – than is typically observed. This is the case because it would be very rare for every end-use customer who has entered into a DR arrangement to be able to provide the full value of their available DR capability at the same time. Quite simply, there are often production requirements that prevent these customers from doing so. Although very high spot market prices will get a great deal of the available DR to dispatch, it is likely that somewhat more is actually available than is exhibited in any particular instance.

DR not yet participating but technically capable of doing so

This is a much larger reservoir of DR capacity. Our investigation revealed that there is a significant level of interest in DR from both customers (once they are aware of the opportunity and its potential benefits) and intermediaries (i.e., retailers and aggregators) and from network companies. The fact that there is likely to be a significant level of DR at least technically possible – and available under particular combinations of operational requirements and financial reward – is corroborated by other studies and experience in other markets.

ClimateWorks published a study in early 2014 entitled *Industrial Demand Side Response Potential*. In this study in-depth interviews were conducted with 34 companies representing 26% of all industrial electricity consumption (and 83% of the electricity consumption in the industrial sectors represented by those companies) regarding their DR potential and the likelihood and circumstances under which they would consider providing DR into the market. The surveys provided insight into the operations, load profile, DR feasibility and factors affecting their ability and willingness to participate in DR programs.

Survey results were combined with information in the *Industrial Energy Efficiency Data Analysis Project* database to provide an estimate of the total DR potential across Australian industry. This extrapolation estimated that somewhere between 3.1 and 3.8 GW of DR is potentially available from industrial facilities across Australia, depending on the level of financial return available and effort and expense required.

Table 4 presents a sample of the information on DR potential identified in the ClimateWorks study. It shows DR potential by industry sector (defined at the ANZSIC sub-division level) and end-use process where the end user expects to (a) obtain returns from the deployment of DR equal to approximately 20% to 30% of the annual costs of running the end use, and (b) be provided with 2 to 4 hours notification of need to dispatch DR..

This potential was identified as a function of the level of financial return available. Two broad ranges of incentive were offered 5 – 15% and 20 – 30% of the total electricity cost associated with the end use from which the DR would be provided. This meant that the survey tested participation acceptance as a function of revenue yield. In actual fact, revenue yield in terms of spot price is a combination of the trigger price the customer is willing to accept in order to provide DR, and the number of times and duration of the events that pool price is above that trigger. Clearly, it is not possible for end-use customers (or even participants in the wholesale market) to know for certain the degree to which those conditions will be met in the future – even over relatively short periods such as a season. For this reason, ClimateWorks used the revenue yield approach to make the question easier for the customers being interviewed to answer. In actual fact, the uncertainty that pertains regarding the decision in the real world would be expected to materially reduce the number of customers that actually decide to provide DR, and to skew participation to those activities that can be undertaken with very little or no capital cost or set-up costs, and to higher price events.

Table 4: ClimateWorks estimate of DR potential by sector and process where DR return equals 20% to 30% of end-use electricity costs and 2-4 hour notice is provided

ANZSIC			End-use process groupings									
Division	Sub-division(s)	Sub-div total	Chemical processing[1]	General industrial[2]	Material handling3	Process htg[4]	Compress-ion[5]	Building svcs[6]	Refrig & cool[7]	Water & waste[8]	Ventila-tion[9]	Back-up gen[10]
Mining	Coal mining	436	0	58	265		10	3				
	Oil & gas	0										
	Metal ore mining	530	66	36	364	21	41	2				
	Non-metallic mineral mining	80	0	15	66							
Manufacturing	Meat & meat products	44		10	6		6	2	20			
	Dairy products	89		15	3		10	7	55			
	Grain mill & cereal products	77		12	50		8	4	2			
	Sugar and confectionery	2										
	Pulp &,paper	279		111	153		4	4				
	Petroleum and coal products	26		13	13							
	Basic chemicals & chemical products	33		18	3	3	3	2	3			
	Polymer & rubber products	61		43	8	9						
	Other non-metallic minerals products	19		1		3						14
	Ceramic products	32		11	20							
	Cement, lime, plaster & concrete products	112		28	70	8		2	4			
	Basic non-ferrous metal products	1059	928	55	16	11	40	3	4	4		
	Fabricated metal products	63		49			5	7	2			
	Motor vehicles and parts	0										
Water and waste services	Water supply, sewerage, drainage	155		32						65		38
Process total		3,092	995	529	1,139	55	129	36	90	69		72

Notes to Table 4

1. Chemical processing – includes electrolysis, other chemical processing and filtration
2. General industrial – includes pumping systems, ventilation, fans and blowers, motors, various industrial machinery, non-transport machinery, and other equipment
3. Material handling – includes commination and blasting, stationary materials handling, conveyors and mining, earthmoving and excavation
4. Process heating – includes electric arc furnaces, furnaces and kilns, blast furnaces ovens, and other process heating
5. Compression – includes compressed air systems and gas compression equipment
6. Building services – includes lighting systems, HVAC systems, IT, comms and other electronics, and other building services
7. Refrigeration and cooling – includes refrigeration and freezing and cooling towers
8. Water and waste – includes water treatment and purification, water desalination, and waste treatment and disposal
9. Ventilation – includes flaring systems, venting and leaks
10. Back-up generation – includes on-site electricity generation equipment

Survey results also indicated that over 95% of the identified potential could be available with 2-4 hours notice with limited requirement for additional investment (i.e., if we assume the potential for DR in the NEM is 3,000MW then with 2-4 hours notice we could expect about 2,850MW to be available for DR service)[23], while shorter notice periods would most likely require some level of investment in automation and addressing potential safety issues and would significantly reduce the potential. Intuitively, if there is less than 15 minutes notification then the expected DR available is likely to be about 10% of the potential (i.e., 300 MW). At 30 minutes to 1 hour we would expect about 50% participation from DR (i.e., 1,500 MW). However even with day ahead notice it is unlikely that 100% participation would be achievable, mainly because there will always be a proportion of the DR (say 2-3% of the total) where the plant is being maintained or the production schedules simply do not make DR provision attractive.

The results of the ClimateWorks study are also broadly in line with experience in some other markets, though it is important to note that market structure can play a significant role in the amount of DR provided. For example, in Western Australia's capacity market, DR represents about 10% of installed capacity. In PJM (the market that serves Pennsylvania, New Jersey and Maryland in the eastern US), which also has a capacity mechanism. DR represents about 8.5% of installed generation capacity. In New Zealand, where DR is used primarily for frequency control, which requires that DR be able to respond immediately (less than 1 second), there is about 200 MW of DR, representing about 2% of installed capacity and 3% of peak demand.

These figures all indicate that there is almost certainly a material level of DR potential within the NEM, as the amount identified by AEMO corresponds to only about 2.5% of the NEM's installed capacity.

Potential likely to be available in the future

Changes in the economy within Australia are likely to change the nature of this potential over time. The loss of manufacturing as a percentage of the economy is likely to reduce the amount of DR available from that sector in total, but improved communications and control technology is likely to make quicker response of the remaining DR potential easier to access. There are also likely to be some emerging industries that can offer significant new sources of DR. One example that has been mentioned is the LNG industry in Queensland which is likely to have significant opportunities for DR in pumping and compression loads.

Network programs such as the Critical Peak Demand pricing program that has been implemented by AusNet Services are popular with intermediaries and many have focused their attention in this geographic area. The network income or savings go to the customer directly or via the intermediary and then any spot exposure or curtailment on peak prices would provide the cream. The recent draft determination regarding the value of cost-reflective network pricing is likely to see a number of similar pricing approaches being put into place and offering a viable platform from which DR could be provided in the wholesale market at times of high price other than when the network tariff calls for it.

At the same time, there appears to be some movement away from direct spot exposure on the part of large end-users within the NEM, and increased interest in working through intermediaries. While this approach limits the customer's choice and flexibility (to a degree) – and therefore reduces the potential savings – it also provides support services to the end-use customer and insulation form price risk.

23 It is worth noting that NEM data suggests that about 3,000MW of generation capacity is used for only 40 hours a year. This is the part of the load duration curve in which DR could provide a competitive source with potential benefits to the market as a whole.

These factors – plus the possible implementation of the Demand Response Mechanism (DRM) currently being considered as part of a potential Rule Change – indicate that effective mechanisms for obtaining greater amounts of DR may be coming on line in the near future, resulting in a materially greater DR resource becoming available[24].

3.7. Experience of DR providers with late rebidding

3.7.1. Nature of relevant market conditions

It is widely recognised that there is at present an over-supply of generation capacity in the NEM. This is generally felt to be the result of:

- softening demand due to the impacts of the Global Financial Crisis (GFC) and structural changes in the nature of the Australian economy with consequent losses in more energy-intensive manufacturing;
- price elasticity effects in response to relatively high year-on-year price rises over the past 5 or so years;
- additional energy consumption reductions driven by Commonwealth and state-based energy efficiency programs; and
- government incentives for large-scale renewables and small-scale, decentralised renewables, particularly rooftop PV systems.

The over-supply has resulted in historically low wholesale market spot prices, and a reduction in price volatility – and because of the combination of these factors, significantly less revenue available over the course of a year from demand reductions that are undertaken at or above the level of price at which DR generally enters the market.

In short, these are not particularly encouraging times for DR[25].

However, while prices and volatility are both depressed as compared to previous years, a number of those consulted mentioned that they (and others) have observed other departures in market price and market price movement in the present market as compared to previous times particularly in South Australia and Queensland. These include:

- significantly less correlation between supply/demand conditions and price than characterised the market previously;
- a significant number of spikes in spot price occurring at times they have not tended to occur in previous years;
- those periods of high price being quite short in duration as compared to previously, and

24 The Demand Response Mechanism would provide payment for documented demand response at spot market prices and allow end use customers with annual electricity consumption in excess of 100 MWhpa to provide that demand response either directly to the wholesale market, or through a market intermediary (called a Demand Response Aggregator). This latter feature would provide more competitive drive for exercising DR in the wholesale market and potentially overcome certain aspects of retailer DR arbitrage programs that have frequently been criticised by end use customers – namely, that retailers retain an inordinately high percentage of the pool price arbitrage available to DR, and that they often fail to call an event in which the price exceeds the end-users' trigger price.

25 These conditions are not entirely bad for consumers, however. Low and relatively stable prices are very good for electricity consumers, at least in the short run. However, where those prices do not allow generators to operate at acceptable commercial returns they can threaten the attractiveness of investment which can create higher and more volatile prices for consumers in the future.

- those periods of significant price increase tending to occur in the last one or two 5-minute Dispatch Intervals of a given 30-minute Trading Interval.

Taken together, these factors have resulted – according to most of the organisations consulted – in it having become much harder to foresee and predict with any acceptable level of accuracy when a period of sufficiently high price to warrant the dispatch of DR is likely to occur.

Virtually all of the organisations consulted felt that these short durations of high spot price, which occur at times that would not be expected given general supply/demand conditions, are the product of bidding behaviour the purpose of which is to increase generator revenue in a market environment characterised by sub-standard returns. Organisations consulted differed markedly, however, on

- whether they saw this as price manipulation or rational economic market behaviour, and
- whether they felt anything should be done to limit such behaviour, and if so what sort of things should be done.

Some of those interviewed – particularly aggregators, specialist retailers and representatives of consumer organisations – commented that given the importance of volatility in the NEM as a signal of the need for new generation, such price spikes which are unrelated to supply/demand elements should be seen as a market failure and an example of market power[26] being exercised by the generators involved. They also noted that the generators who either drive or profit from these price spikes most often tend to be baseload facilities that shift volume in the first 20 to 25 minutes of the trading interval to capture more market demand and then dramatically reduce their output in the last five minute of a trading interval, sometimes combining those actions with a rebid of a portion of their capacity at a very high price. Either or both of these practices can force the price to the next generator bid that meets the level of demand. Particularly at times of low demand, the next bid can be close to or at VoLL – this explains the spurious nature of these price events and why they often happen at strange hours.

Some of those interviewed believe that these generators have taken to using these strategies very frequently, however, their efforts only bear fruit when market conditions are right.

Virtually all of the organisations consulted – including the large end users – agreed that instances in which prices have suddenly and significantly changed in the last one or two Dispatch Intervals have occurred with some frequency lately, and that this pattern has not been observed until quite recently. They also agreed that these price patterns have tended to occur primarily in Queensland and South Australia and virtually exclusively result from coal-fired baseload facilities shifting volume between bands. When gas is available and the gas plants can foresee the price run and put in bids despite these events happening outside times of normally tight supply/demand conditions, the incidence of late rebidding appears to abate.

These respondents also said that they expect this type of behaviour to continue even once market prices improve due to a reduction in the current over-supply of generation capacity. They felt that now that this behaviour has been seen to be successful in increasing baseload generation revenue, it would remain an attractive commercial behaviour in the future.

26 It should be noted that in economics there is a technical definition of market power. The definition generally includes reference to the ability of a firm (or firms) to manipulate the price of a good or service such that it is persistently and consistently above long-run marginal cost. The term as used by those interviewed may not have been meant in this technical sense, but was certainly used to reflect pricing that these respondents felt was both opportunistic and inappropriate (i.e., not in accordance with the intent of the market design or Rules).

3.7.2. The nature of late rebidding on DR in the context of the NEM's 5 minute/30 minute price-setting mechanism

The impact of late rebidding within the NEM's 5-minute/30-minute price setting mechanism is different depending on whether the rebid occurs toward the beginning or the end of a 30-minute Trading Interval as discussed in further detail below.

The cost incurred by a load in the wholesale market is calculated as follows:

(total volume of electricity consumed by the load customer in the Trading Interval)

X *(average spot price in the Trading Interval, which is calculated as the arithmetic average of the 6 five-minute market clearing spot prices within the half hour of the Trading Interval)*

X *(transmission loss factor X distribution loss factor).*

As a result, if there is a high price at the beginning of the Trading Interval, the dispatch of DR can reduce the amount of volume exposed to the half-hourly price that will be affected by the high spot price of the initial Dispatch Intervals.

However, if the same level of price characterises the last one or two 5-minute Dispatch Intervals, the dispatch of DR (a) will only be able to affect the volume within the half-hour period if it can be put into effect very quickly, but (b) regardless of whether that can be accomplished or not, the electricity consumed during the earlier four or five 5-minute Dispatch Intervals will have already taken place and will not be able to be kept from having an impact on the cost incurred by the load for the overall 30-minute period.

In addition to adding significant risk for DR providers, the short duration of these high-price events also reduces the savings or income that can be earned through DR – and this is the case regardless of whether the DR is provided by a end-use customer taking direct exposure to peak price, or an aggregator who provides a firm price to end-use customers and in doing so takes on the associated price risk[27].

The following paragraphs explore the impacts of rebidding using examples illustrating how those impacts differ depending on when in the Trading Interval the late rebidding occurs.

Late rebidding comes without warning and is often unrelated to the underlying supply/demand balance. It can happen in any part of a Trading Interval – Figure 5 below illustrates a late rebid that occurs in the last 5 minutes of a Trading Interval.

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27 It is also interesting to note that this pattern of pricing is very difficult for a peaking generator, in that it puts them at risk of not running during a high price period which would be likely to require them to pay out on cap contracts they have taken up with retailers, but leaving them with no pool revenue to cover those payments in the event that they did not bid and therefore did not generate during the relevant Dispatch or Trading Intervals.

Figure 5: An example of the impact of late rebidding on 5-minute Dispatch Interval prices and on the Trading Interval price

Scenario 1

Assume a 1MW DR participant is monitoring prices and can immediately curtail their load on the appearance of a price spike. They will be expecting a price of $65/MW for the Trading Interval based on the observed prices in the first five 5-minute intervals. However, at the last 5 minute interval the price reaches $12,000/MWh and at that point the customer curtails their load.

Assuming that the 1MW load is the entire site load, then the customer has exposed its load to an average Trading Interval cost of $2,054.17/MWh for an average load of 833kW (i.e., 5/6ths of 1 MW) which equates to a total price of $855.90 for the half hour.

Scenario 2

A more realistic scenario occurs where the customer needs 5 to 10 minutes to curtail that same 1MW of load. In that case they would miss the event entirely and therefore expose their full 1MW of load to the average price (i.e., their cost would be $1,027.08) for that half hour.

Second Guessing the Generators

Interviewees noted that it is possible to see the generators positioning themselves to spike the price by progressively taking on load early in the trading interval only to drop their output to force the price to the next highest bid that covers the demand level.

Assuming that the customer who is exposed to the pool price is monitoring the actions of the generators and recognises when they are jostling for position, it is possible that the customer could curtail the load prior to the price spike, even with a 5 to 10 minute preparation time. However this poses two issues for the customer:

- The generators are likely to be trying to create spikes at every possible opportunity. So even though the customer has visibility of these actions by the generators and can take actions to limit their exposure to the price spike they cannot curtail every time they think price will surge, given the disruption that can cause to production.
- The customer would still be exposed to a higher price during the Trading Interval even if they can dispatch in time (as shown in Scenario 1 and 2 above).

3.7.3. Implications for DR of the late rebidding currently being experienced in the NEM

The overall findings in the study with regard to the implications of late-rebidding for DR are that:

- Current market conditions in the NEM have significantly reduced the likely economic returns from DR because
  - average price has reduced to historically low levels, and
  - there are fewer hours during which pool price exceeds the trigger price at which DR typically enters the market.

  This makes DR of any sort less economic than it has been in previous years. :

- In addition to the lower overall returns that are currently available for DR, the rebidding that has been experienced in the NEM in the last year or two (a) has further reduced the amount of DR that is applicable to the nature of high price events and (b) entails higher levels of risk for DR providers, for the following reasons:
  - A much higher proportion of the high price intervals that do occur in the market at present are the result of rebidding – and particularly rebidding that occurs late in the Trading Interval. These instances of high price are difficult to predict, and generally do not last long – generally 15 minutes or less, and often for no more than 5 minutes[28].
  - As such, responding to these events limits the use of DR to those resources that can take action very quickly upon notification of a potential high price event and ramp down facility demand very quickly.

    The aggregators and retailers that were consulted who are relatively active in working with customers to identify, arrange and deliver DR all reported that the only DR that can respond to these price events – and the only resources they are actively dispatching any more – are those that can deliver their target DR levels within 30 or preferably 10 minutes. One of these respondents reported that this has reduced the effective amount of DR available from his customers by 95%.
  - Even where customers can respond, the nature of these high price events makes them extremely risky. Because the events are hard to predict, the choice is to either (a) dispatch DR whenever there is a chance of such an event in order to avoid the high price that is likely to last for one or two Dispatch Intervals but influence the price that will be applied to all electricity consumed by the customer in that Trading Interval, or (b) to only respond when the price event is definite.

    The primary risk in the former situation is that the high price may not eventuate and any effort or loss in production experienced by the DR provider will have essentially been wasted. It is also the case this entails significantly more monitoring and, where the DR is dispatched in response to a notification from a retailer or an aggregator, there will be significantly more notifications than previously, which requires more attention from the end-use DR provider. This runs the risk of fatiguing the DR provider and making DR seem too hard.

    The primary risk in the latter situation is that DR is not dispatched, and the party at risk (the customer if they are exposed to pool price, or the retailer in the case of a retailer program) is exposed to the spot price for the full load.

28 DR providers generally prefer to participate in events lasting longer than 30 minutes at a time. Some, such as hospitals and other emergency services, prefer to run their generators for the entire day when they know for certain that their DR is required.

- Altogether, current market conditions are very poor for DR. One retailer reported that many of the customers that had been exercising DR to offset their own pool price exposure (and who are under partial pool price exposure retail contracts) have decided not to take that exposure any more. As a result, that DR capability will no longer be available to the market.

  In addition, all of the parties involved with DR that were consulted stated that the potential returns for DR in the wholesale market are inadequate at present for most end use customers. Increasing reliance is being placed by retailers and aggregators on network applications of DR to justify the involvement of end-use customers. However, where those do not exist, the business case for DR at present is generally quite weak.

- It was also mentioned that late rebidding poses similar problems for peaking generators as it does for DR providers. Peakers need to be generating at times when the caps they sell will be called on, as it is the spot revenue that provides the funds for payments against the cap. Because the rebid high price events are hard to predict and have generally occurred at times when peakers do not typically generate, several peakers have 'missed' high price events, entailing significant financial payouts uncompensated by pool revenue. It was reported that in response, one peaker has reconfigured its plant to allow it to go to full load within a few minutes. This required a material capital expenditure and on-going costs to keep the generator spinning at a minimum level. However, the generator in question felt these costs were justified on commercial grounds including the avoidance of risk and increased flexibility of operation.

  Some of those interviewed – generally retailers associated with generation businesses -- cited this as a self-correcting aspect of the market: one party finds a way to gain competitive advantage and another finds a way to counter-act it. These respondents felt this was evidence that the market does not need intervention. They also expressed the view that interventions should be avoided wherever possible on the grounds that they often have unforeseen and distortionary effects.

  Others, while recognising that such a response could mitigate the impact of the current instances of late rebidding, questioned whether such a solution was in the best long-term interests of consumers, as it will, of necessity, increase costs while providing no net benefit to consumers. Those respondents tended to see the current form of late rebidding as an abuse of market power[29]. Their view was that in these instances a generator was exploiting a temporal and in some cases a geographic position in which no other party can respond to the resulting price signal. These respondents felt that this was a product of the incumbency position of the causal generator in the bid stack and the technical limitations on other parties to respond. In short, they saw these events as 'cash grabs' rather than responses to supply/demand conditions.

29 As noted earlier, there is a technical definition of market power, and it is not clear whether these respondents were using the term in its technical sense or more generally to refer to opportunistic and inappropriate pricing behaviour.

- In one of the interviews conducted early in the project the idea of an early gate closure was put forward as a possible 'fix' for the late rebidding problem. It was noted that there is no other energy-only market that operates without a gate closure mechanism, along with some sort of balancing mechanism to respond to supply/demand mismatches that arise after gate closure. It was recognised that the timing of the gate closure would be critical. For best results, the gate closure would need to be early enough to allow other generators and customers with DR capability to respond, but short enough to allow bids to be based on as good information as possible about supply/demand conditions and to limit the volume of adjustments needing to be handled in the balancing mechanism.

  Several of the respondents – generally retailers associated with generation businesses -- were not in favour of any gate closure. They cited the self-correcting possibilities of the market and also (a) felt it is imperative that analysis be undertaken to determine whether the rebidding was actually producing any material disbenefit in the market before deciding there is a 'problem' that needs to be fixed, and (b) expressed concern that changing this basic aspect of the market could be costly and engender further distortions with more significant impacts than the original 'problem' caused by rebidding.

  All of the aggregators and large customer that provide DR that were interviewed and even one or two of the retailers felt that a gate closure anywhere from 30 minutes to 2 hours prior to the Trading Interval should be considered as a means for improving the ability of DR to make a positive contribution to the NEM. Most felt that 1 hour would provide the best compromise for providing a better basis for DR while avoiding undue volumes needing to be dealt with through a balancing mechanism.

  In this regard, it is worth noting that, earlier this year, the Southwest Power Pool in the US introduced a 5-minute settlement with a 10 minute gate closure. Early indications are that this appears to have negated the need for a balancing market[30].

30 While this is a very interesting and potentially useful result, it should be noted that (a) it is an early result, and (b) it does not mean that this result would be experienced in other markets or that any gate closure interval longer than 10 minutes will necessarily require a balancing mechanism.

Appendix A: Organisations consulted

Type of organisation	Organisations consulted
DR aggregators and advisors	EnerNOC Global-Roam GreenSync
Retailers	AGL Energy EnergyAustralia ERM Origin Energy Progressive Green
Customer representative organisations	Energy Users Association of Australia (EUAA) Major Energy Users Inc (MEU)
Networks	Ausgrid AusNet Services Energex Endeavour Energy TransGrid
Large electricity users	Adelaide Brighton Ltd Consultant to Coles Orora Limited Telstra Visy
Others	AEMO Owner/operator of a gas-fired peaking generator