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Impact of Demand Response in the Australian National Electricity Market with High Renewable Energy Penetration

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Abstract

Price responsive demand, or demand response, can reduce the overall industry cost of meeting peak demand periods and is a potentially valuable source of power system flexibility. It is becoming increasingly valued in electricity industries around the world as system operators look for new approaches to securely manage power systems with tightening generation reserves and greater variable renewables deployment. The capabilities and applications of demand response are expected to increase significantly in the future, making it important to better understand the opportunities yet also challenges of demand response for power system operation, particularly in high renewable future scenarios.

This paper presents a study assessing the present and possible future role of demand response for the Australian National Electricity Market (NEM). A preliminary analysis of historical wholesale spot pricing and demand data is performed to identify and characterise existing unscheduled demand response in the NEM. A case study demonstrating the effect of this existing short term demand response over an eight hour period in Queensland is then examined. Next, NEM simulations using PLEXOS are undertaken to explore outcomes when the amount of demand response in the NEM is increased from present levels, and the extent to which demand response might offset peaking generation and provide flexibility to facilitate high penetrations of variable renewable generation.

The empirical analysis of market data finds that a modest amount of existing unscheduled demand response can already be observed in the NEM. The modeling simulations suggest that increasing the amount of scheduled demand response from present levels to a potential 3 GW could greatly decrease the number of high price events and reduce price volatility. In a base case that reflects the current generation portfolio in the NEM, the average wholesale price decreased by 13% resulting in an 18% reduction in the total annual industry cost of energy. In a high renewables scenario (50% wind and 10% PV by energy), an 18% reduction in average price was observed across the NEM, decreasing total costs by 23%. In another high renewables scenario (40% wind, 25% PV), the average wholesale price was reduced by 26% with a reduction of 35% in the total cost of energy.

1. Introduction

Traditionally in electricity industries, demand has been treated as exogenous from the supply side, with conventional generation such as coal-fired and gas plants required to match changing demand. However, with the growing use of wholesale electricity pricing, improved consumer ‘smarts’, the significant growth of renewable energy generation and increasing distributed energy options, this paradigm is changing; the demand side is becoming increasingly important as a market participant and, particularly, a potential source of flexibility. Demand response (DR) is a central component of demand side management that refers broadly to the active change of usual or “baseline” electricity consumption in response to changing electricity industry conditions (Aghaei & Alizadeh 2013). This active change of consumption is generally accomplished by reducing or shifting loads, or with local supply through storage or backup generation. The type of DR considered in this paper is price responsive demand, specifically demand that responds to temporally varying wholesale electricity prices, as opposed to typically smaller-scale tariff-based DR. The modernisation of the grid, including deployment of advanced metering and control technologies and increasingly intelligent consumer load equipment will significantly expand the capabilities, and hence potential impact of DR. It is therefore important to better understand the effects that DR might have on electricity industry operation and hence appropriate ways to best facilitate it. This is particularly true of Australia’s National Electricity Market (NEM) where reserve margins have been falling while wind and solar penetrations have grown significantly, and the capabilities of DR have been traditionally underutilised. A summary of the potential benefits of DR is listed in Table 1.

Table 1. Overview of Potential DR Benefits (Albadi & El-Saadany 2008)

Consumer	• Bill savings or incentive payments
Market Wide	• Lower price and reduced volatility
Network	• Avoided and deferred infrastructure costs, e.g., network augmentation • Increased capacity
Reliability	• Operational security and adequacy savings due to lowered likelihood of forced outages
Market Performance	• Mitigates ability to exercise market power

Importantly, in addition to the benefits, high amounts of unscheduled DR in an electricity market may increase the challenges associated with forecasting and hence system operation. Unscheduled DR refers here to price based DR that is not advised to and then scheduled by the market operator. It is particularly problematic for the market operator since it is not certain if and when the demand will respond. In addition, attempting to forecast unscheduled DR can create an equilibrium adjustment process that may not converge. This is illustrated in Figure 1, for a supply curve S with demand that responds at some price point P between P_1 and P_2. A demand Q_0 results in a price P_0 which activates DR, reducing the demand Q_1 and the price to P_1, “deactivating” the DR, which increases the demand back to Q_0 and price to P_0, and so on. Scheduling of DR can help to alleviate this problem, but presents challenges of its own, such as the design of the mechanism.

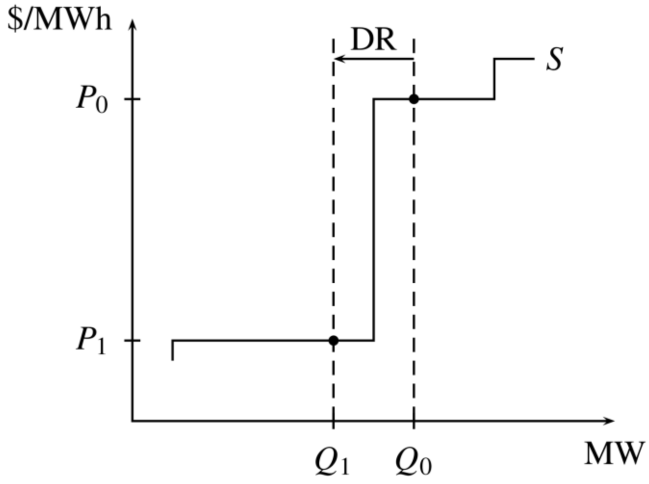

Figure 1. Equilibrium Adjustment Process

This paper presents a study assessing the present role of unscheduled DR and possible future role of scheduled DR for the Australian NEM. A preliminary analysis of historical wholesale spot pricing and demand data is performed to identify and characterise existing unscheduled DR in the NEM. Then, NEM simulations using PLEXOS are undertaken to explore outcomes when the amount of DR in the NEM is increased from present levels, and used to offset peaking generation and provide flexibility to facilitate future high penetrations of variable renewable generation.

In the next Section, specific details of the NEM context for DR are provided as background for the paper. Section 0 contains an analysis and discussion of demand forecast errors in the NEM, as well as a case study. Section 4 outlines the methodology and choice of scenarios for the market simulations of increasing levels of DR and variable renewables, and a discussion of results. Finally, conclusions are made in Section 5.

2. The Australian NEM and DR

Internationally, the dominant route for DR participation in energy markets is through capacity mechanisms, which pay resources to be available to provide energy (Brown et al. 2015). The NEM is an energy only market that does not incorporate a capacity mechanism, and does not contain an explicit demand response mechanism (DRM) for purchasing DR as a substitute for generation. At present in the NEM, therefore, wholesale DR is achieved through either direct exposure and response of the load to spot prices, or aggregation and response to spot prices via a retailer (ENERNOC 2014). An explicit DRM was proposed in 2015, stemming from a recommendation contained in the Power of Choice Review but was not implemented (AEMC 2016).

In 2016, the Australian Energy Market Operator (AEMO) estimated that there is about 700 MW (exclusive of future LNG projects in Queensland) of price responsive load across all regions in the NEM (AEMO 2016a), corresponding to approximately 2% of peak demand (AER 2017). These AEMO estimates, broken down by region and price at which the response activates, are shown in Table 2.

Table 2. AEMO Estimates of Demand Response 2016 to 2017 (MW)

Price Trigger	NSW	QLD	SA	TAS	VIC Not Summer	VIC Summer	Total
$300/MWh	38.3	27.3	15.4	4.9	76.7	76.7	162.6
$500/MWh	50.2	27.9	16.6	4.9	79.0	79.0	178.6
$1,000/MWh	53.2	28.6	17.2	4.9	81.5	81.5	185.4
$7,500/MWh	61.0	82.6	88.1	15.2	85.0	141.8	388.7
Market Price Ceiling ($14,000/MWh)	248.5	147.5	120.2	43.0	85.0	141.8	701

AEMO's estimates are produced by analysing historical observed price response in metered demand data, and through a survey of network businesses and market participants, particularly large industrial loads, which are understood to be accounting for the majority of the observed response. It is noted that this large industrial load response is a probable resource rather than a firm resource and may respond differently at different times.

A ClimateWorks study estimated that there is 3.8 GW of industrial DR potential Australia wide (Garvin & Denis 2014), or approximately 12% of peak demand. This estimate can be contrasted with experiences in markets that have well developed DRMs such as the PJM Interconnection in eastern United States (8.6% of peak demand) and ISO New England in the north-east United States (7.4%) (Brown et al. 2015; ENERNOC 2014; Garvin & Denis 2014). In the NEM, if available DR corresponded to 10% of peak demand, then there would be approximately 3–3.5 GW of DR, more than 3 times the estimated amount currently participating, albeit in a nonscheduled manner, in the NEM. This estimate forms the basis of the market simulation scenario described in Section 4.2.2 of this paper.

3. Data Analysis

AEMO produces regional load forecasts every 5 minutes to set dispatch targets in the next dispatch interval for generation in the wholesale market, hence determining the spot price in each region. These forecasts are based on a neural network forecasting model that does not directly account for price responsive demand (AEMO 2014). The model takes the measured demand of previous dispatch intervals to predict future demand in the next interval and does not consider the impact of the resulting price that occurs. However, unscheduled price response is captured in the forecast for the subsequent period, since the measured demand will be reduced. Of course, a changed price forecast in response to this demand reduction might then see that demand return in the next period. We undertook preliminary analysis of such unscheduled DR by calculating the error in the dispatch forecasts and observing any relationship with the associated spot price.

Five minute dispatch forecasts from 2009 to 2017 were accessed from the NEMWEB Data Archive[1] and the errors between the dispatch target and actual demand were analysed. The errors are categorised into spot price groups that match AEMO's DR estimation methodology.

[1] The relevant AEMO csv files are DISPATCHREGIONSUM and DISPATCHPRICE. The error is computed from the entries: CLEAREDSUPPLY, INITIALSUPPLY and AGGREGATEDISPATCHERROR.

Note that the market price ceiling in 2009 was $10,000/MWh (AEMC 2009), so this is taken as the cutoff for the final category. This forms a distribution of errors for each pricing category and region, allowing the median error (50% POE) to be calculated, shown in Table 3. Observe that a positive error implies the actual load was lower than expected suggesting potential price response.

Table 3. Median (50% POE) Error in 5 Minute Dispatch Forecasts 2009-2017 (MW)

Price ($/MWh)	NSW	QLD	SA	TAS	VIC
−1,000 to 300	−1.21	5.79	2.76	3.60	7.81
300 to 500	15.51	20.63	8.04	7.74	8.10
500 to 1,000	27.58	27.20	15.66	2.42	−17.47
1,000 to 7,500	12.20	43.93	17.58	10.75	-0.33
7,500 to 10,000	5.08	35.16	12.35	20.68	3.46
10,000+	14.84	46.55	31.39	23.49	11.74

Demand over estimation is clear for almost all regions and price intervals. The ‘imputed’ DR values are much lower than those estimated by AEMO for DR. This is an expected outcome given that the DR reflected here is short term only: if a high price event were forecast an hour or more ahead, it is likely that the DR would react at a prior interval in a planned way. Additionally, if there were a previous high price, DR may have already been activated and the load not yet brought back online. The difference also demonstrates the practical difficulty of estimating DR without specific metering and energy consumer surveys. It is important also to note that prices over $300/MWh are significantly less frequent than prices under $300/MWh, meaning there are far fewer dispatch intervals and therefore more uncertainty in the results. The average number of intervals for each price category over $300/MWh is 509 (out of a total 844,941 intervals per region). The relative rarity of high price events highlights one of the challenges in estimating price response, as noted in AEMO’s estimation methodology (AEMO 2015). A market based DRM reduces the need to estimate the amount of DR since it becomes visible to the market operator. However, depending on the mechanism, there may still be a need to estimate a ‘baseline’ of what demand would have been without the DR.

The existence of forecast errors still suggests the presence of unscheduled DR in the NEM. With the amount of DR likely to rise in the future, the error in these forecasts and the need to account for it in power system operation, also seems likely to increase. A rule change was made in 2015 that, when implemented, will require registered participants to submit information about demand side participation under their control to AEMO, with the intent of addressing this information deficiency (AEMC 2015).

3.1. Case Study: Queensland, 2nd February 2017

In addition to the dispatch forecasts discussed above, AEMO produces an hour-ahead predispatch forecast which estimates 5 minute demand over the next hour, published every 5 minutes. Similar to the dispatch forecasts, these do not directly account for price response. DR events can therefore be inferred.

The chart in Figure 2 shows the actual 5 minute spot price and demand in Queensland on the 2nd of February 2017 between 12:00 and 20:00, where the 5 minute spot price exceeded $12,000/MWh in 15 intervals. In several of these high price intervals, a noticeable drop in demand is seen, indicating that demand is responding to price. Predispatch forecasts are used to represent the demand with this price response removed. Using this forecast demand, an estimated price can be calculated based on median price observed at a given demand level over this 8 hour period. These imputed demand and prices without DR are also shown in Figure 2.

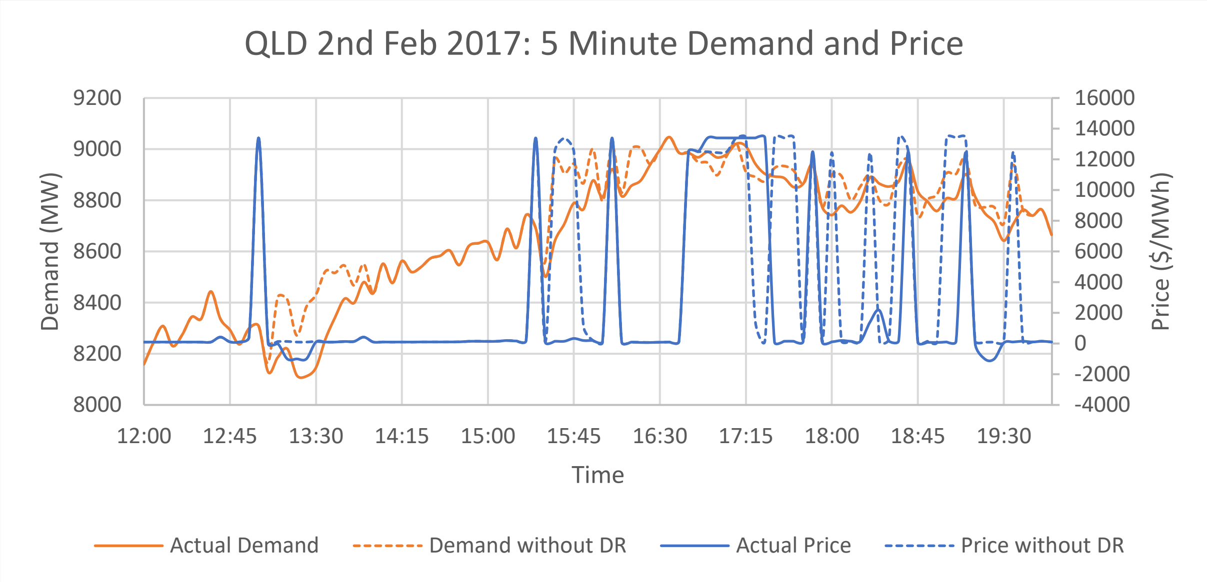

Figure 2. 5 Minute Demand and Price for QLD region, 2nd Feb 2017, including actual demand and price, and imputed demand and price without DR

During this period, the bid stack is extremely sensitive to changes in demand, with little to no generation bidding between $100/MWh and $14,000/MWh resulting in highly volatile prices. This explains why the price is very sensitive to a relatively small increase in demand and why the price without DR spikes more than the actual price observed. The analysis suggests that the price response observed in the actual demand may have reduced the average price in QLD over this period by 40% from around $3,500/MWh without DR to $2,100/MWh with DR. Under 30 minute settlement prices, the total cost of energy over the period is reduced 40% from around $250m to $150m using the imputed prices, demonstrating a significant impact of existing DR on the spot price during times of high prices.

4. Market Simulations

4.1. PLEXOS

PLEXOS is a commercial integrated energy modelling tool widely used in the simulation of energy markets (Energy Exemplar 2017). AEMO has published PLEXOS files containing a model of the NEM that is used in the development of the Electricity Statement of Opportunities (ESOO) to give a projection of supply adequacy over the next 10 years (AEMO 2016b). The 2016 ESOO PLEXOS file is adapted to create the model used in this paper.

The model is set up to run a short term (ST) schedule at a 30 minute resolution for 2 years, which emulates dispatch of a market clearing engine using mixed-integer programming based chronological optimisation. The traces used as a basis for demand and variable renewable energy generation correspond to the 09/10 financial year while the simulation timeframe are the financial years 17/18 and 18/19, with corresponding adjustments to demand and generation portfolio in the ESOO. Start up times and costs for coal generation are sourced from an ACIL Allen technology review (Kelp, Lenton & Choudhuri 2014) and implemented additional to the existing ramp rates, fuel costs, outage rates and repair times. Hydro storages and waterways, as well as existing transmission constraints are included as per the ESOO model.

DR is modelled in the ESOO model as an internal property on each “region” object, but for this work has been moved into separate lossless, high operating cost, generators for each region of the NEM – a common approach in the literature (Hoch et al. 2014; Hummon 2014; Ma & Cheung 2016), as it allows for better customisation of the model and reporting. For this work, the DR “generators” are modelled with price-quantity pairs that are bid into the market, corresponding to the amount of demand that responds (i.e., the generator is “dispatched”) at or above particular price levels. The DR is compensated with the wholesale spot price, as a generator would be. This market based mechanism solves the issue of a nonconvergent equilibrium adjustment process by allowing the DR to effectively be the marginal generator and set the spot price, which does occur occasionally in the simulations and has a minor impact on spot pricing relative to if the DR were unscheduled.

4.2. Scenarios

4.2.1. Generation Portfolios

Three generation scenarios are modelled to investigate the impact of high levels of DR: a base case that represents the current generation portfolio, and two high renewables cases that represent possible future portfolios with high variable renewable energy penetration.

The base portfolio contains generator objects for all units registered in the NEM as of 2016, accounting for the closure of the Hazelwood power station. It was found that the base case produced relatively flat, constant prices, even when accounting for unplanned outages and competitive bidding. It is common for market models to produce such ‘well behaved’ pricing relationships, because they do not account well for competitive bidding and exercise of market power, particularly around technical constraints and uncertainties that may not be reflected in the model (Hoch et al. 2014). In order to simulate high price events, scarcity of generation is created by scaling all generation down until the reliability (the amount of unserved energy over the total energy demand) falls just within 0.002%, the reliability standard for the NEM (AEMC 2013). This scaling factor was found to be approximately 0.8, meaning the capacity of all generation is scaled down by 20%. This is necessary to ensure that high price events occur and therefore DR is activated over the simulation period. High prices in the model occur primarily due to high demand but can also occur because of unplanned outages.

The high renewable generation portfolios are based on a portfolio used by Wilkie (2015), which was developed using NEMO (National Electricity Market Optimiser) to hit a target of 80% renewable energy. Additional wind and solar traces were added to the base portfolio from a ROAM Consulting study (ROAM Consulting 2012) in order to increase the locational diversity of wind and solar resources. The specific traces used correspond to the onshore wind and utility PV polygons used in AEMO’s 100% renewables feasibility study (AEMO 2013). Lumped generators were created for each of these traces, with capacities equal to the average capacity of existing wind or solar generators. Nine new wind generators were implemented, and ten new solar generators, dispersed across all regions in accordance with the polygons. The capacities of each generation type were then scaled up or down to meet the capacity ratio in the 80% renewable portfolio. A second high renewable portfolio was created with a PV capacity closer to that of wind. After the capacity ratios were adjusted, the entire generation portfolios were scaled until the 0.002% reliability standard was met, as for the base case. The resultant portfolios are described in Table 4. Note that the variation in the total energy generated between the base and high renewable portfolios is due to decreased losses from conventional generation self-consumption.

Table 4. Generation Portfolios

	Base		**High Renewable 1**		**High Renewable 2**	
Generation Type	**Capacity (MW)**	**Energy (GWh/year)**	**Capacity (MW)**	**Energy (GWh/year)**	**Capacity (MW)**	**Energy (GWh/year)**
Coal	19,600	158,000	5,960	42,100	5,950	35,500
Hydro	6,010	16,200	9,620	12,300	9,590	14,500
Gas	8,130	18,000	18,400	27,100	18,300	21,400
Liquid Fuel	552	37	-	-	-	-
Wind	3,380	9,654	54,600	99,200	37,200	78,300
Solar	168	289	7,500	16,900	24,800	48,900
Total	*37,840*	*201,976*	*96,080*	*197,568*	*95,840*	*198,600*

4.2.2. Demand Response Scenarios

For each generation portfolio, two scenarios of DR are considered for comparison. The first represents current levels of DR, assumed to be AEMO's estimates described in Table 2 which total 701 MW. The second scenario assumes 3 GW of DR is available (broadly based on the ClimateWorks estimate of industrial DR potential), equivalent to approximately 10% of peak demand as described in Section 2. It is assumed that the proportion of DR by price level and region remains the same for both scenarios.

4.3. Results

The distribution of spot prices is a useful measure of the impact of increased DR. For both generation portfolios, the average spot price and standard deviation are observed to decrease, as shown in Table 5 and Table 6. Here the average spot price decreases by 13% for the base portfolio, 18% for the first high renewable portfolio, and 26% for the second high renewable portfolio. The total standard deviation is reduced by 51%, 74% and 85% for the respective portfolios.

The decrease in average spot price resulted in an 18% reduction in the total industry cost for the base case from $34,000m to $28,000m over the two year period. For the first high renewable portfolio, total cost is reduced by 23% from $24,000m to $18,000m and for the second high renewable portfolio, the reduction is 35% from $22,000m to $14,000m. The total industry cost falls more than the average spot price since the industry cost is volume weighted, meaning high demand during high prices increases the total cost relative to a simple average.

Table 5. Average Spot Price over 2 Year Period ($/MWh)

	Base		High Renewable 1		High Renewable 2	
	DR Current	**DR High**	**DR Current**	**DR High**	**DR Current**	**DR High**
NSW	64.18	56.71	64.95	53.72	60.45	43.92
QLD	56.09	49.58	89.72	67.12	75.73	47.52
SA	113.07	94.75	9.62	9.62	8.20	8.20
TAS	93.19	85.83	4.39	4.05	2.17	2.13
VIC	108.49	90.49	31.34	30.00	31.97	29.70
NEM	*87.01*	*75.47*	*40.00*	*32.90*	*35.71*	*26.29*

Table 6. Standard Deviation of Spot Price over 2 Year Period ($/MWh)

	Base		High Renewable 1		High Renewable 2	
	DR Current	**DR High**	**DR Current**	**DR High**	**DR Current**	**DR High**
NSW	276.37	26.68	402.42	120.49	466.56	71.44
QLD	253.50	25.46	558.04	117.97	615.58	70.74
SA	600.66	330.04	23.73	23.73	22.65	22.65
TAS	286.39	16.65	84.03	16.21	11.42	11.12
VIC	592.97	329.69	139.07	50.85	172.32	50.07
NEM	*433.07*	*210.23*	*318.02*	*83.47*	*355.27*	*54.65*

The varying reduction in average spot price across the three scenarios suggest that DR may complement the variability of renewable generation, particularly solar generation. High price events contribute significantly to the average spot price and the standard deviation. By reducing the incidence of these events (Figure 3), increased DR reduces the volatility of spot pricing. The number of intervals with prices over $10,000/MWh decreases from 157 to 30 for the base portfolio, from 83 to 2 in the first high renewable portfolio and from 106 to 0 in the second high renewable portfolio over the 2 year simulation period.

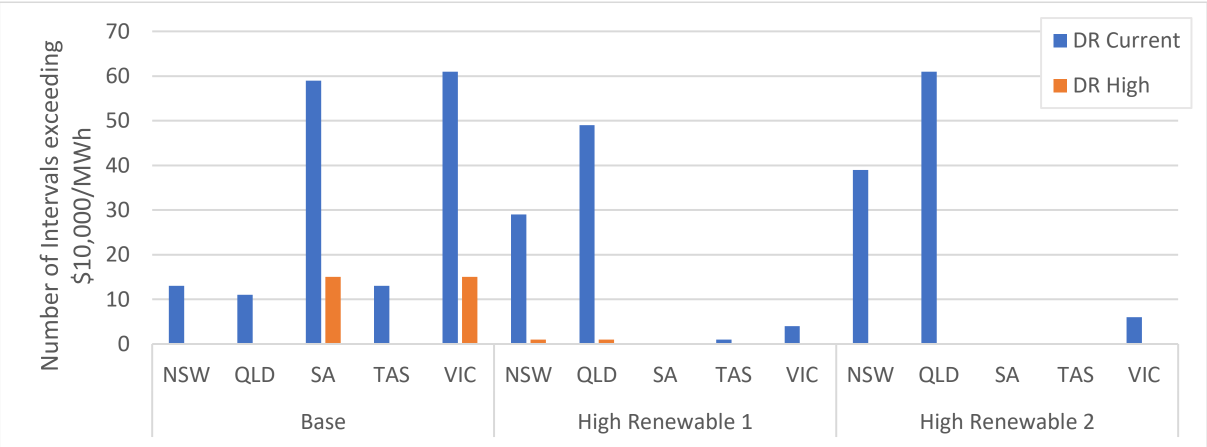

Figure 3. Number of Intervals where Spot Price exceeds $10,000/MWh

A reduction is also observed in the amount of unserved energy (USE). Over the two year simulation period, the USE in the base portfolio is reduced from 7.5 GWh to 0.0 GWh, in the first high renewable portfolio from 7.3 GWh to 0.0 GWh, and in the second high renewable portfolio from 7.7 GWh to 0.0 GWh, demonstrating the potential value of DR as a flexible resource. Note that the decrease in high price events due to DR acts to reduce opportunities for DR since it would be triggered less often. Indeed, when doubling the potential DR to 6 GW, the average price was reduced only an additional 2% for each generation portfolio.

For both high renewable generation mixes, the percentage change in energy generated by each generator type due to increased DR were found to be relatively minor. Differences were less than 0.5%, with the following exceptions: energy generated from liquid fuel in NSW decreased by 10% in the base case, and energy generated from natural gas in TAS decreased by 6% in both high renewables cases. The DR displaced these peaking generators during times of high prices, but the DR capacity is not large enough to significantly offset other generation. Interestingly, the utilisation of DR in VIC decreases when the capacity of DR is increased in other regions, since the DR in other regions offsets its use through the interconnectors.

An important limitation in the modelling are sustained periods of constant price, which can create unintuitive results when comparing total energy generation for specific units. This is especially relevant for the high renewable scenario in which sustained periods of $0/MWh prices coincide with the bid price of wind, hydro and solar, creating a situation where the marginal generator is not well defined. Increasing the amount of DR (which changes the generation mix) can sometimes trigger different marginal generators to be dispatched during these periods, creating these unintuitive results. This effect is observed with hydro generation between the base and high renewable portfolios where increased capacity results in lower overall generation. An additional concept that is not considered in the modelling is how strategic behaviour of generators may change in an attempt to minimise price reductions due to increased DR, which could influence potential impacts.

5. Conclusion

Analysis presented in this paper has shown that price responsive load appears to increase the errors in AEMO’s dispatch forecasts, highlighting the challenges associated with forecasting unscheduled DR. The impact of existing DR has also been investigated with a case study over an 8 hour period in Queensland, during which it is estimated that DR reduced the average spot price by 40% and reduced the total energy cost to load by 40%.

Market simulations performed to examine the effects of DR suggest that increasing DR levels to an estimated 3 GW, estimated to be the industrial potential, might significantly impact the average spot price. Increasing DR reduced the average spot price by 13% in the base scenario, reflective of the current generation portfolio, and by 18% in a high renewable portfolio with significant wind, and 26% in a scenario with a more equal mix of PV and wind. Increased DR was also found to decrease the volatility in spot prices since it reduces the number of intervals with very high prices, indicating that DR can be highly valuable during periods of scarce generation. Reliability was also found to increase with increased DR, with no unserved energy under high amounts of DR in each portfolio. The capabilities of DR depend on the presence of high price events, which are likely to be fewer when there is already significant DR present.

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