

Aggregated Effect of Demand Response on Performance of Future Grid Scenarios

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Abstract—The existing future grid (FG) feasibility studies have mostly considered simple balancing, but largely neglected network related issues and the effect of demand response (DR) for modelling net future demand. This paper studies the effect of DR on performance of the Australian National Electricity Market in 2020 with the increased penetration of renewable energy sources (RESs). The demand model integrates the aggregated effect of DR in a simplified representation of the effect of market/dispatch processes aiming at minimising the overall cost of supplying electrical energy. The conventional demand model in the optimisation formulation is augmented by including the aggregated effect of numerous price anticipating users equipped with rooftop photovoltaic (PV)-storage systems. Simulation results show that increasing penetration of DR improves loadability and damping of the system with the increased penetration of RESs.

Index Terms—Demand model, demand response, future grids, power system stability, renewable energy sources.

I. INTRODUCTION

Future grid (FG) feasibility studies have analysed the viability of relying on higher penetration of diverse renewable energy sources (RESs) in power systems in the long term of several decades [1]–[6]. Due to intermittency of RESs, those studies have considered enough backup generation and/or utility storage to keep the network in balance. Australian researchers have suggested that relying 100% on RESs for the Australian National Electricity Market (NEM) can be technologically feasible using a copper plate transmission model [1]–[3]. Furthermore, the least-cost mix of 100% RESs scenario for the future of the NEM has been determined in [3]. Similarly, the least-cost mix of high penetration of diverse RESs and conventional generation has been determined for the future of the PJM, California and New Zealand networks in [4]–[6], respectively.

However, those studies have only focused on simple balancing, and neglected the network related issues (e.g. line overload and stability) by using a simplified grid model such as the copper plate model. So far, a German study [7] appears to be the only one that has considered stability aspects by including voltage and frequency stabilities in a network model. Due to all the new features of FGs (e.g. RESs, demand-side control, etc.), it is essential to study performance, stability and security of FG scenarios after basic balancing studies.

It is to be noted that penetration of distributed generation (DG) in power systems has been increasing significantly in recent years, and greater penetration of battery storage is anticipated [8]–[12]. In Australia, installed capacity of rooftop photovoltaic (PV) has grown from approximately 0.8 GW in 2011 to over 4 GW in 2014 [11]. Recent studies have suggested that retail price parity for users equipped with PV-storage systems appears highly plausible from 2020 in the NEM [10], [12]. Also, similar issue has been recently addressed for users equipped with PV-storage systems in the USA grids [8], [9]. Consequently, these newer demand-side developments necessitate the need for aggregated net demand modelling (including DG, storage and demand response (DR)) to study FG scenarios. While the effect of DR is neglected in most of the existing FG feasibility studies [1]–[5], [7], it is considered in a few studies mainly through two different ways:

Group 1: DR is considered implicitly, but it is not reflected into the loads. For instance in [6], New Zealand researchers have considered the effect of DR through improving the capacity credit value for intermittent RESs (i.e. intermittency of RESs is decreased). However, due to the significant effect of loads on performance and stability of power systems, it can be expected that incorporating DR explicitly into the load models will affect the results of FG feasibility studies significantly.

Group 2: In two recent studies [12], [13], the aggregated effect of DR is reflected into the conventional load models. The Australian Commonwealth Scientific and Industrial Research Organisation (CSIRO) FG Forum has made a first step by proposing a simple aggregated demand model at state levels in the NEM [12]. A further step towards aggregated demand modelling considering DR is made in [13] assuming users are price anticipators. That model is suitable for system studies at transmission levels, and is briefly reviewed in the next section.

In this paper, the effect of the aggregated demand model considering DR [13] is studied on performance of FG scenarios using the simulation platform in [14]. The platform considers market simulation, load flow calculation and stability assessment together. In case studies, the aggregated effect of DR on balancing, loadability and small-signal stability of the NEM in 2020 is studied using a modified 14-generator model [15]. The dispatch results from the market are used as

initial conditions/equilibria for balancing and stability studies in DIGSILENT PowerFactory. Five scenarios are analysed with one business as usual (BAU) and four different levels of DR with renewable integration. For the BAU Scenario in 2020, the electricity supply is dominated by coal, gas, hydro, and biomass; and in the Renewable Scenarios, some of the conventional coal generators in Queensland and South Australia are replaced with wind farms (WFs) and concentrated solar plants (CSPs) with storage, as suggested in [1], [16] to meet the Australia's RES target [17]. Simulation results show that increasing the penetration of DR improves loadability and damping of the system with the increased penetration of RESs.

The remainder of the paper is organised as follows: Section II briefly reviews the aggregated demand model considering DR. Section III describes the test-bed assumptions and modelling. Section IV describes simulation scenarios, and discusses simulation results. Finally, Section V concludes the paper.

II. AGGREGATED DEMAND MODEL CONSIDERING DR

Aggregated load models are commonly used in system studies to reflect the combined effect of numerous physical loads [18]. Conventional aggregate load models only account for the accumulated effect of numerous independent load changes and some relatively minor control actions. Including the effect of DR requires allowing for the interaction between demand and supply sides in some way, e.g. price signals. In the previous study by the authors, an aggregated demand model considering DR is proposed [13]. This demand model integrates the aggregated effect of DR in a simplified representation of the market/dispatch processes, and is inspired by the traditional unit commitment problem. The associated optimisation problem aims at minimising the overall cost of supplying electrical energy in which the conventional demand model is augmented by including the aggregated effect of numerous users equipped with newer demand technologies. The demand model consists of two parts: (i) a fixed electricity demand profile (inflexible demand), and (ii) flexible demand equipped with demand-side technologies (we consider a large homogeneous population of residential and commercial PV-storage systems, but the model allows an easy integration of other demand technologies as well). Also, the demand model considers the following main assumptions:

Assumption 1: Users are assumed to be price anticipators, i.e. the effect of users' actions is considered on the electricity price by the load aggregators. Due to the price anticipating assumption, load aggregators are considered implicitly.

Assumption 2: Aggregators do not change the total energy consumption of the users, but instead systematically manage and shift it.

In the next section, the DR model is formulated as an optimisation problem and subsequently used for the simulation scenarios.

A. Optimisation formulation

The objective function of the optimisation model which aims at minimising the overall electricity cost is written as

follows:

$$\min \sum_{h=1}^H \sum_{n=1}^N C_G^n(P_G^n(h)), \quad (1)$$

where, h , n , P_G^n and $C_G^n(P_G^n)$ denote time slot, supplier, active power and cost function of supplier n , respectively. The objective function is subject to the following constraints:

1) *Power generation limit:* Generation of suppliers are constrained between the minimum and the maximum power limits as follows:

$$P_G^{\min,n} \leq P_G^n(h) \leq P_G^{\max,n} \quad \forall h, n, \quad (2)$$

2) *Flexible demand, storage and PV:* The following set of equations augment the conventional demand model by including the aggregated effect of numerous price anticipating users equipped with PV-storage systems.

$$P_F^{\min,m} \leq P_F^m(h) \leq P_F^{\max,m} \quad \forall h, m, \quad (3a)$$

$$\sum_{h=1}^H [P_{LF}^m(h) - P_{PV}^m(h)] \Delta h = E^m + E_{\text{loss}}^{\text{B},m} \quad \forall m, \quad (3b)$$

where, m denotes a load aggregator. Flexible demand of each load aggregator, P_F^m , is a decision variable which reflects the aggregated effect of DR. This variable is constrained between the minimum and the maximum limits in (3a). The overall energy balance over time horizon H is also given by (3b). Fig. 1 demonstrates a simple illustration of the demand profile. As it can be seen in Fig. 1a, the aggregated net demand of each load aggregator, P_{LF}^m , is equal to the sum of inflexible and flexible demands, i.e. $P_{LF}^m(h) = P_L^m(h) + P_F^m(h)$. $P_F^{\min,m}$ represents the interaction between the price-responsive users and the grid (e.g. when $0 \leq P_F^{\min,m}$, the model represent a situation where price-responsive users do not send power back to the grid). The flexibility of loads is due to battery storage which is modelled implicitly by considering the upper limit of the flexible load power as $P_F^{\max,m}(h) = P_{\text{B,cha}}^{\max,m} + P_U^m(h)$. Note that $P_{\text{B,cha}}^{\max,m}$ is a limiting variable to ensure that the total storage capacity is not exceeded, and it does not represent a physical property of a particular battery technology. This variable can be determined heuristically, as explained in detail in [13].

The aggregated flexible demand is determined by each load aggregator in (3b) in a way that the total energy requirement for that aggregator, E^m , remains constant (*Assumption 2*) considering aggregated PV generation, P_{PV}^m , and also battery storage energy loss, $E_{\text{loss}}^{\text{B},m}$. Total energy requirement of aggregator m over the horizon can be written as $E^m = \sum_{h=1}^H (P_L^m(h) + P_U^m(h)) \Delta h$. $E_{\text{loss}}^{\text{B},m}$ in (3b) guarantees that battery round-trip efficiency is also taken into account. As it is shown in Fig. 1b, part of the required energy for price-responsive users is provided by PV. So, the rest of the energy has to be supplied from the grid (i.e. $E_1^m + E_3^m - E_4^m$). Price-responsive users utilize battery storage to shift their consumption from expensive hours to cheaper time slots in order to minimise the overall cost of supplying electrical

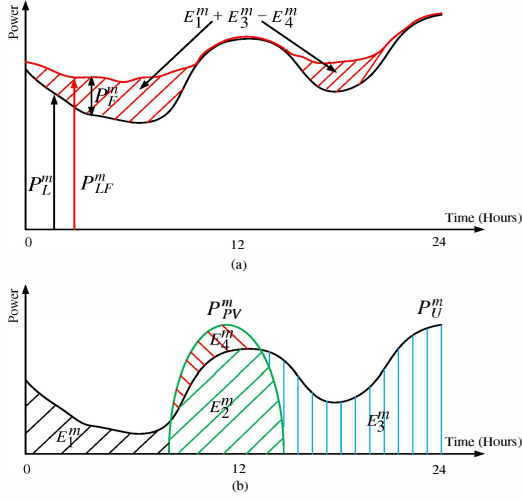


Fig. 1. Simple illustration of the demand profile (a) aggregated flexible demand, inflexible demand and new net demand profile, and (b) aggregated price-responsive demand and PV generation.

energy (i.e. $E_1^m + E_3^m - E_4^m$) can be spread out over the horizon due to enough battery storage of price-responsive users in a way that the overall electricity cost minimises like the red area in Fig. 1a). In other words, the total flexible demand energy over the horizon is equal to the energy which has to be supplied from the grid plus battery storage energy loss, i.e. $\sum_{h=1}^H P_F^m(h)\Delta h = \sum_{h=1}^H (P_U^m(h) - P_{PV}^m(h))\Delta h + E_{\text{loss}}^{B,m} = E_1^m + E_3^m - E_4^m + E_{\text{loss}}^{B,m}$.

3) *Demand supply balance*: Ignoring the losses in the grid, the power balancing equation can be written as (4a):

$$\sum_{n \in r_i} P_G^n(h) - \sum_{m \in r_i} P_{LF}^m(h) = \sum_{r_j} P_L^{r_i, r_j}(h) \forall h, r_i \in R, \quad (4a)$$

$$P_L^{r_i, r_j}(h) = B_{r_i, r_j}(\delta_{r_i}(h) - \delta_{r_j}(h)), \quad \forall h, (r_i, r_j) \in R, \quad (4b)$$

$$P_{L, \min}^{r_i, r_j} \leq P_L^{r_i, r_j}(h) \leq P_{L, \max}^{r_i, r_j} \quad \forall h, (r_i, r_j) \in R, \quad (4c)$$

where, r_i and B_{r_i, r_j} denote node i in the system and susceptance of line between nodes i and j , respectively. The power transferred by lines between different nodes, $P_L^{r_i, r_j}$, in the system is given by (4b), and is constrained by the line limits in (4c).

In the optimisation formulation, battery storage is modelled implicitly and its state of charge (SOC) is not a decision variable. However, it is important to consider battery SOC limits to make sure that the available storage capacity in the grid is not exceeded. $P_{B, \text{cha}}^{\max, m}$ in the demand model is a limiting variable which ensures that the available storage capacity in the grid is not exceeded. This variable is determined heuristically, as explained in detail in [13].

III. THE AUSTRALIAN NEM MODEL

A 14-generator model of the NEM, which was originally proposed for small-signal stability studies [15], is used as the test-bed in this paper. Fig. 2 shows the schematic diagram of the 14-generator model. Areas 1 to 5 represent Snowy Hydro (SH), New South Wales (NSW), Victoria (VIC), Queensland

(QLD) and South Australia (SA), respectively. The Australian Energy Market Operator (AEMO) planning document has proposed 16 zones for the NEM in order to capture differences such as generation technology capabilities, costs and weather to the future [16]. We matched the 14-generator model and the 16 zones to be able to extract data for the demand model and also generators in 2020. The match between those two is demonstrated in Fig. 2. Each region of the 14-generator model (i.e. QLD, NSW, VIC and SA) is considered as a node for the demand model. Consequently, interstate lines are considered explicitly in the demand model. However, balancing and stability studies are done using the test-bed shown in Fig. 2.

In Section IV, the effect of the demand model will be illustrated on the balancing, loadability and small-signal stability of the NEM in 2020 with the increased penetration of RESs using the simulation platform in [14]. The platform considers market simulation, load flow calculation and stability assessment together. The generator technologies and the test-bed assumptions in this study follow the studies in [13], [14]. In market simulations, the fossil-fuel generators were assumed to bid their bidding behaviour [13], while RESs' bid is assumed to be zero. If supply cannot meet the demand, the hour is recorded as the unserved hour. However, if available generation exceeds demand (i.e. due to high generation of RESs), the surplus power is recorded as dumped energy and that hour is marked as a dumped hour.

The excitation systems (AVR) and power system stabilisers (PSS) of generators are adopted from [15]. Also, it is assumed that all thermal, gas and hydro power plants have standard governors: IEEE1 for steam turbines, GAST for gas turbines and HYGGOV for hydro turbines. CSP controllers are assumed to be similar to thermal power plants. For wind, a fully rated converter-based WF model in DIGSILENT which is based on the generic wind turbine model [19] is used in this study. The modified 14-generator model of the NEM is then modelled in DIGSILENT Power Factory, and the dispatch results from the market are used as inputs for DIGSILENT for balancing and stability studies.

IV. SIMULATION SCENARIOS AND RESULTS

The effect of different levels of DR on the load profile, balancing, loadability and small-signal stability of the NEM in 2020 with the increased penetration of RESs in the grid is demonstrated in this section.

A. Simulation scenarios

Case studies include five scenarios with one BAU and four different levels of DR with renewable integration. For the BAU Scenario, a combination of coal, gas, hydro and biomass are considered to supply the load in 2020 (i.e. Scenario 1). Then, some of the conventional coal generators in QLD and SA are replaced with CSPs together with storage and WFs, respectively to meet the Australia's RES target. Displacement of the conventional generators in the Renewable Scenarios and the chosen capacities for the RESs are inspired by [1], [16].

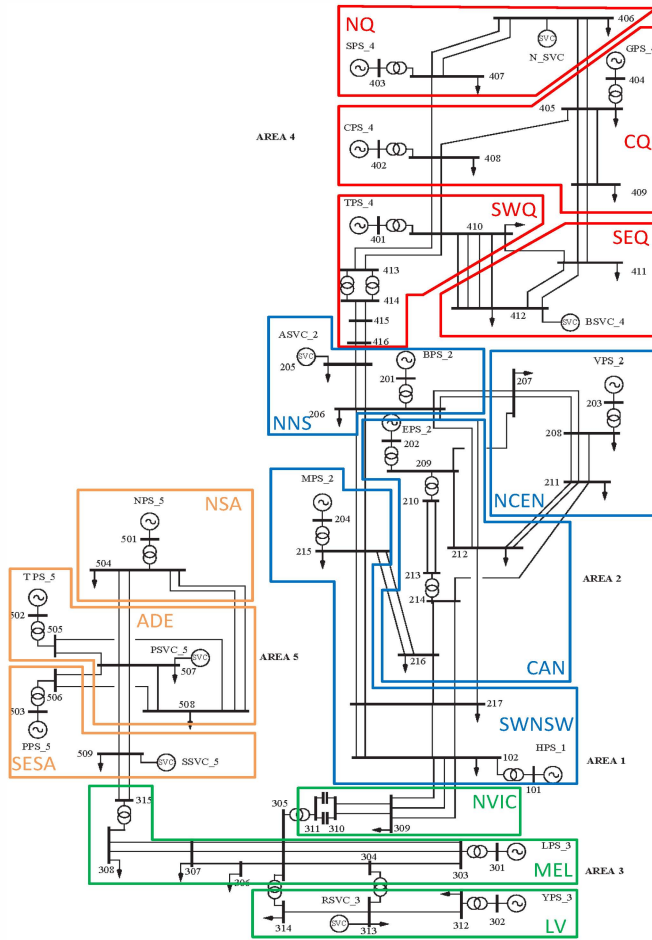


Fig. 2. 14-generator model of the NEM.

NPS_5 in SA is replaced with a WF with the capacity of 3 GW using NSA data [16]. SPS_4 and GPS_4 in QLD are replaced with two CSPs with the capacity of 4.5 GW each and using NQ and CQ data [16], respectively. It was found that delaying CSP output by 12 hours minimises the unserved and dumped energy. The RESs serve about 20% of the total demand energy in the Renewable Scenarios.

In this study, hourly demand and PV power for the demand model are obtained from the AEMO predications for 2020 [16]. Also, DR is considered for the residential and commercial customers, which are considered to account for 60% of the total system load in the NEM in 2020 [16]. The industrial customers are left unaffected. The percentage of the price-responsive customers with PV are considered 20%, 30% and 40% for low, medium and high uptake scenarios, respectively. Table I shows the aggregated storage and PV capacities for each region of the NEM and for different uptake scenarios. The chosen PV capacities for different uptake scenarios are inspired by the AEMO study [20]. Also, the chosen storage capacities roughly correspond to a typical PV and storage capacity for a household in Australia. Using the heuristic algorithm proposed in [13], $P_{B,cha}^{\max,m}$ is calculated for different

TABLE I
THE AGGREGATED STORAGE AND PV CAPACITIES FOR EACH REGION OF THE NEM FOR DIFFERENT UPTAKE SCENARIOS

Region	Scenario	$B_{SOC}^{\min,m} - B_{SOC}^{\max,m}$ (GWh)	$P_{B,cha}^{\max,m}$ (GW)	PV capacity (GW)
QLD	Low	0.4-4.3	0.44	1.3
	Medium	0.6-6.4	0.63	1.9
	High	0.9-8.5	0.83	2.6
NSW	Low	0.7-6.7	0.62	2.0
	Medium	1.0-10.1	1.01	3.0
	High	1.4-13.5	1.34	4.1
VIC	Low	0.5-5.0	0.47	1.5
	Medium	0.8-7.5	0.72	2.3
	High	1.0-10.0	0.95	3.0
SA	Low	0.1-1.2	0.10	0.3
	Medium	0.2-1.7	0.16	0.5
	High	0.2-2.3	0.22	0.7

DR scenarios, and is reported in Table I. In the rest of the paper, the Renewable Scenarios with conventional load, low, medium and high uptakes of DR are called Scenarios 2 to 5, respectively.

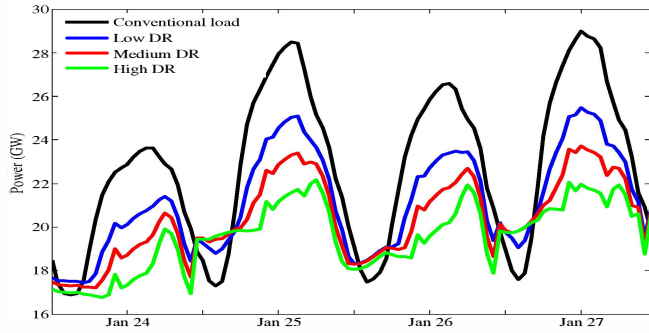
B. Load profile

Figs. 3a and 3b show the effect of different DR penetrations on the load profile resulting from solving the demand model (Section II) for the NEM during one of the summer and winter peaks in 2020, respectively. As it can be seen in Figs. 3a and 3b, users shift their consumption using PV-storage systems from expensive time-slots to cheaper ones to minimise the overall electricity cost. In other words, price-responsive users shift their consumption using PV-storage systems to utilise cheaper electricity produced by RESs (i.e. to minimise the overall electricity cost). So, DR can help balance fluctuating RES power and demand. Note that all the results in this section assume that price anticipating users do not send power back to the grid (i.e. $P_F^{\min,m} \geq 0$) at the aggregate level.

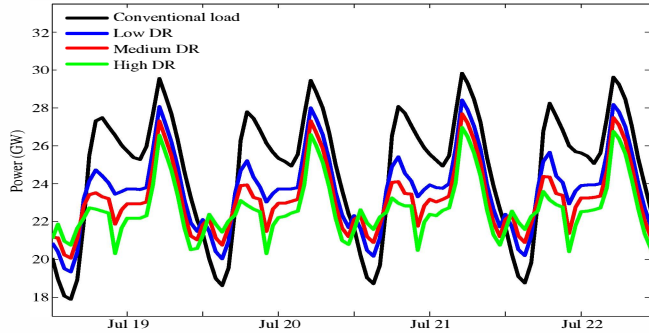
C. Balancing and stability results

The results of balancing, loadability (LDB) and small-signal stability for all the scenarios over the simulated year are summarised in Table II. For loadability calculation, all loads in QLD are assumed to increase uniformly in small steps with constant power factor until power flow fails to converge. Also, it is assumed that all the generators in QLD are scheduled with the same participation factor to pick up the system loads. The loadability is computed for each hour until a step before power flow divergence. Also, damping ratio of the least stable rotor angle mode in the system is calculated for each hour using the eigenvalue analysis (i.e. QR method).

Comparing the BAU Scenario and the Renewable Scenario with the conventional load (Scenario 2), it can be seen that with the increased penetration of RESs, the required electrical energy from backup supply (i.e. GTs) is increased from 18.73 TW to 18.77 TW. Also, the average loadability is reduced from 27.13 GW to 22.17 GW. This is mainly due to lack of reactive power support for the grid from



(a)



(b)

Fig. 3. Demand profile for the NEM for Scenarios 2-5 in one of the critical (a) summer, and (b) winter peaks.

RESs (including converter-based WFs). However, the minimum damping ratio is increased from 9.03% to 10.14% with the increased penetration of converter-based WFs in SA. While the minimum damping ratio is improved, unstable hours in terms of small-signal stability (i.e. hours in which the least-stable rotor angle mode is placed on the right half plane (RHP) of the eigenvalue plot) are increased from 0 to 39 hours. The least damped modes of the system are mostly related to three inter-area modes. Speed eigenvectors and participation factors show that those modes are oscillatory modes in which:

- Mode 1: Generators in VIC oscillate against the rest of the system;
- Mode 2: Generators in SA oscillate against generators in VIC;
- Mode 3: Generators in QLD oscillate against generators in NSW.

Instability mainly happens under two situations:

Case A: High generation from WFs and low demand in SA. In such a situation, generation in VIC increases (i.e. generation in VIC are cheaper than the conventional generators in SA) to compensate the mismatch between generation and demand. Increasing the internal rotor angle of those generator(s) which have significant participation on Modes 1-2 can result in small-signal instability for those hours.

Case B: Similar to Case A, under low generation from CSPs and low demand in QLD, generation in NSW increases to compensate the mismatch between generation and demand. Increasing the internal rotor angle of generation in NSW which

TABLE II
BALANCING, LOADABILITY AND SMALL-SIGNAL STABILITY RESULTS

Scen.	Spilled energy (TWh)	Spilled hours (%)	GT energy (TWh)	LDB (GW)	Damping ratio (%)	Unstable hours
1	-	-	18.73	27.13	9.03	0
2	0.71	13.65	18.77	22.17	10.14	39
3	0.66	13.03	18.28	24.82	10.28	23
4	0.61	12.67	17.78	25.86	10.34	15
5	0.54	11.71	17.04	26.24	10.58	5

have significant participation on Mode 3 can result in small-signal instability for those hours.

Compared to Scenario 2, higher penetrations of DR improve loadability, minimum damping ratio, and reduce the required energy from the backup supply. The average loadability and minimum damping ratio are increased from 22.17 GW and 10.14% for Scenario 2 to 26.24 GW and 10.58% for Scenario 5. With demand reduction due to DR during peak loads, the rotor angles of the generators which have significant participation on Modes 1-3 are mainly reduced. Consequently, more damping is provided for the grid, and loadability is also improved during those hours. For medium loads, both detrimental and beneficial impacts can be observed. Under light loads, with demand increase due to DR and because of interstate line limits, balancing in SA is maintained with local generation, and therefore the transferred power from VIC to SA are reduced. So, the rotor angles of the generator(s) in VIC which have significant participation on Modes 1-2 is decreased, and the minimum damping ratio is improved for those hours. Similarly, under light loads, balancing in QLD is maintained with local generation, and the internal rotor angles of the generator(s) in NSW with significant participation on Mode 3 are reduced. So, this improves the minimum damping ratio for those hours. As an example over the simulated year, Figs. 4 and 5 show the minimum damping ratio and the loadability results for the typical summer and winter peaks shown in Figs. 3a and 3b, respectively.

With dispatch changes due to DR, unstable hours are also reduced from 39 hours in Scenario 2 to 5 hours in the high DR Scenario. Fig. 6 shows the dominant modes in one of the unstable hours over the simulated year. As it is shown in the Fig. 6, with increased penetration of RESs and no DR, the least-stable rotor angle mode for the BAU scenario (i.e. point A which is a Mode 3) moves to the RHP in the eigenvalue plot (point B). As described before, the internal rotor angles of the generator(s) which have significant participation on Mode 3 is decreased due to DR, and therefore more damping is provided for the system. So, the least-stable rotor angle mode is moved in the eigenvalue plot from the point B for Scenario 2 to the point C for the high DR Scenario.

V. CONCLUSION

This paper has studied the effect of an aggregated demand model considering DR on performance of FG scenarios. The demand model integrates the aggregated effect of DR in

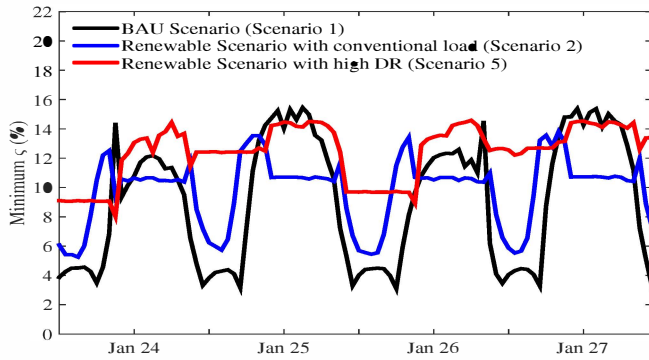


Fig. 4. Minimum damping ratio during typical summer peaks.

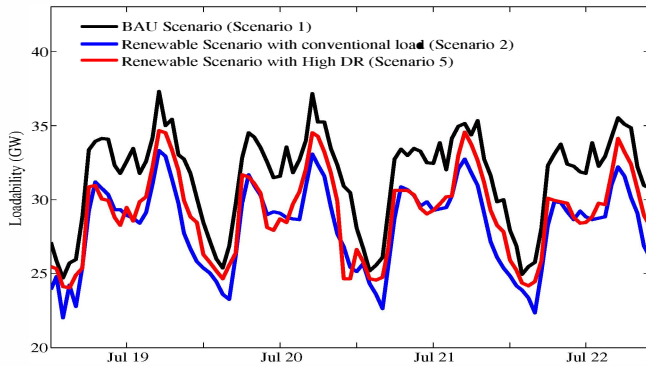


Fig. 5. Loadability results during typical winter peaks.

a simplified representation of the effect of market/dispatch processes. The optimisation formulation aims at minimising the overall cost of supplying electrical energy in which the conventional demand model is augmented by including the aggregated effect of numerous price anticipating users equipped with PV-storage systems. As a case study, the effect of the demand model on the balancing, loadability and small-signal stability of the NEM in 2020 with the increased penetration of RESs is studied using the 14-generator model.

Simulation results show that with the increased penetration of RESs and no DR, loadability is reduced, but the minimum damping ratio is improved. Also, unstable hours in terms of small-signal stability are increased. On the other hand, with increasing penetration of DR, balancing, loadability and minimum damping ratio in the grid are improved with the increased penetration of RESs. Furthermore, the required backup supply, and unstable hours in terms of small-signal stability are reduced.

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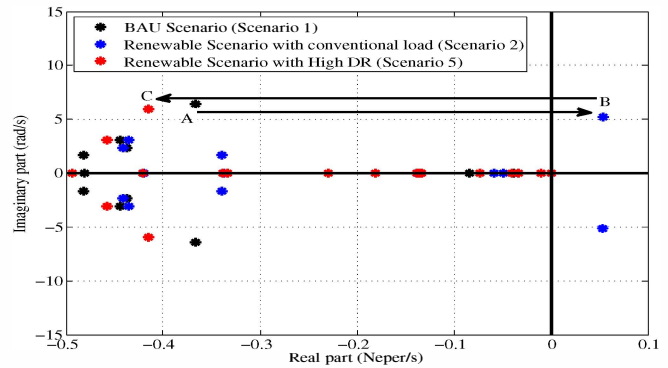


Fig. 6. Dominant eigenvalues for scenarios 1, 2 and 5 at 3 a.m., 22nd of June 2020.

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