A Nascent Market for Contingency Reserve Services Using Demand Response

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Abstract—

The increased presence of variable renewable generation drives a greater need for authorities to procure more ancillary services (AS) for grid balance. One of these services is contingency reserve (CR), which is used to regulate the grid frequency in contingencies. Many Independent System Operators (ISO) are structuring the rules of AS markets such that demand response (DR) can participate along side traditional supply-side resources. The available capacity of the generators can be used more efficiently for power production which they were designed for and not CR; cutting costs, and reducing pollution. As the ratio of inverter-based generation compared to conventional generation increases, the mechanical inertia used to stabilize frequency decreases. When coupled with the sensitivity of inverter-based generation to transient frequencies, the provision of ancillary services from other sources than generators becomes increasingly important. This paper provides a method to use AS for providing CR using DR to ensure system stability for a set of credible contingencies, while also satisfying economic and market goals. In the AS market, optimal power flow (OPF) is used to find the optimal offers/bids and transient behavior of frequency is considered. Our model separates DR into two categories—faster and slower—based on the deviation from the normal frequency of grid power. In a standard numerical example, we show that the proposed model can clear energy and ancillary service bids simultaneously while minimizing the total operating cost and satisfying transient frequency requirements.

*Index Terms—*Ancillary Services (AS), Contingency Reserve (CR), Demand Response (DR), Optimal Power Flow (OPF)

I. INTRODUCTION

Security for grid power delivery and distribution systems can refer to many things. On a basic level, we define security as the ability of a certain system configuration to continue to function and withstand a wide range of operating parameters, outside influences, or even subsystem failures [1, 2, 3]. To design a grid which is secure, a number of factors need to be considered. In the event of contingencies such as short circuits, large changes in load, or loss of transmission lines, the entire system needs to be able to remain operating long enough for the grid operators to restore stability. Maintaining a balance of power is critical to the continued operation of the grid at these times. In order to increase the capacity to maintain this balance of power, grid operators call upon what are known as ancillary services (AS) to provide these changes in power to the grid quickly [1, 4].

AS are typically products provided by a resource capability—generator reserve capacity, etc.—and are contracted to stand by for a request to deliver changes in power to balance grid conditions on very short notice [1, 5]. AS include regulation up, regulation down, spinning reserve, non-spinning reserve and Volt/Var support (Reactive Power) [6, 7, 8, 9, 10, 11, 12]. AS are different from other power products in that they are purchased just so they might be available for an emergency. They are paid for whether utilized or not. Frequency responsive reserves are one type of AS and are services sufficient to cover the contingency of unplanned trips (or disconnect) of a large generator or transmission line to maintain system balance and recover frequency droops in line power signals. Contingency reserves (CR) are generally split between spinning and non-spinning reserves and are often based on the largest single hazard (generator or transmission capacity). Contingency events are big (many megawatt) and fast (within a few cycles) [13, 14, 15].

In order to plan the integration of AS, three questions should be answered: How much should be purchased? How should we prioritize the order in which resources are used? Who should pay for these services? There are two approaches for providing AS: compulsory provision by utility and the creation of market for AS vendors [16, 17]. Also, Battery storage can provide different services such as peak shaving, load smoothing and contingency management. These services can be offered in a vertical or deregulated market structure [18, 19, 20]. Choosing the appropriate approach depends on the type of service and nature and history of the power system. Compulsory provision may provide more resources than needed and cause unnecessary investments. One of the problems that can arise is that of ineffective use of generation capacity. Some generators are inherently more efficient

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than others. Running the most efficient generators at half of load capacity for CR becomes wasteful [1, 21]. The focus of this paper is to describe the development and design of a spot market for vendors of AS and the application of this market in the effective implementation of demand response (DR) as an AS. There are several advantages to the creation of a market for AS over compulsory provision. Grid operators purchase only the amount of service needed and only participants that find it profitable provide services. This provides for a system that becomes financially sound. The market serves to determine the true cost of AS and brings the overall cost of implementation down [1].

Grid operators are faced with the challenge of stabilizing transmission and distribution systems after system failures or other contingencies. From a system designer's viewpoint, it is desirable to maximize grid security. In a perfectly designed system, no component would ever be made to function outside its safe operating range, and would be able to continue to operate following subsystem failures or other grid contingencies long enough for an operator to restore the system. By this, we mean that the power system should remain stable following any of the common disturbances and that it should be able to continue operating in this new state long enough to give the operator time to restore the system to a normal state. Optimal power flow (OPF) is a method which allows operators and designers to find the operating parameters for a given system which will minimize the overall cost.

DR is Voluntary (and compensated) load reduction used as a bulk system reliability resource. Demand-side provision is a good source of AS, because the larger number of participants increases competition, lowers cost and leads to a better utilization of resources. For example, reserve can be provided with interruptible loads rather than partially loaded thermal generating units. This is particularly important if the proportion of generation from renewable sources increases substantially [22, 23, 24, 25, 26, 27]. Generating units can then be used for producing electrical energy rather than as sources of CR [28]. Additionally, the demand side may be a more reliable supplier of some ancillary services than large generating units [29]. The probability that the demand side may fail to deliver a critical service on time is indeed smaller. This service would be provided by the combination of a large number of relatively small loads, all of which are much less likely to fail at the same time than a single large generating unit. Some consumers (for example, those who have large water pumping loads equipped with variable speed drives) might also be able to compete for a share of the AS market [30]. One of the shortfalls of the current state-of-the-art is that customers who place a higher value of security are not able to pay to receive higher security from the grid individually. Thus the system operator provides an average level of security to all customers and the cost of ancillary services is shared by all users on the basis of their consumption [1].

DR is one of the tools that helps to alleviate grid stress as a result of increases in renewable generation. The Federal Energy Regulatory Commission (FERC) has been passing rules in an attempt to level the playing field between traditional and alternative grid resources such as DR and mandating that fast acting resources be compensated for the additional security that their flexibility brings the grid. Conceptual studies have argued that DR is ideally suited to provide AS to the grid and limited field tests have examined their technical capability. The majority of DR literature focuses on its traditional uses such as emergency load relief, system peak management [31] and price responsive demand. The major differences between traditional applications of DR and DR for AS are the reduction of notification time, and the increased speed and accuracy of measurements. There are different algorithms for using DR to provide ancillary service like minimizing the amount of manipulated loads [32], and using an automated system architecture for DR [33].

Behrangrad et al. [34] investigated optimal reserve scheduling through demand response to see what impact it would have on reducing pollution and emissions. The focus of the study was to minimize the social costs as related to providing energy, the purchase of AS, grid stability, and pollution. In [35], a model was proposed in which demand response is utilized by using flexible bidding to create an active market for distributed ancillary services. The goal of the model was to minimize the net system costs for the system states that may occur with reasonable probability in [36]. We see that for the provision of system reserves, a smart agent system can be implement which can incorporate the outputs of stochastic market optimization problems. Using SA-Q learning algorithms, the proposed agent would continuously work to increase effectiveness in increasing the ratio between cost and benefit by adjusting how much system reserve to offer and at which time. Ancillary Service Demand Response (ASDR) programs were proposed to handle multiple contingencies in a power system using a constrained unit commitment problem [15]. Rezaei [37] also proposes a novel energy management system to coordinate and manage DR and distributed generation. In this method we see a hierarchical frequency control structure which uses microgrid components whose individual models are described in [38]. The components acted in concert to keep the frequency of the system within defined constraints. A linearized ancillary service demand response program had been proposed in order to seek active participation of consumers in the grid frequency management. Chen [39] used security constrained economic dispatch (SCED) and security constrained unit commitment in order to analyze how demand response resources are appropriated during market clearing processes. Gitizadeh and Aghaei [40] implemented Corrected Transient Energy Function (CTEF) and a linearized form of Corrected Transient Energy Margin (CTEM) as dynamic security index to consider the transient stability issues of power system. They considered the transient stability which might be decreased because of hitting security limits or increasing the contribution of risky participants. A framework proposed in [41] considered the dynamic security aspects of power systems in the scenario-based market operation. Two objective functions are optimized including: expected social welfare and expected CTEM. This multi-objective optimization clears the market of the joint energy and reserve auctions. In another study, Aghaei [42] proposed another multi-objective optimization to clear the market of joint energy and reserve auctions ensuring power system security. These objective functions were: generation costs and security indices.

In describing the method to implement DR as a source of AS for CR we apply our spot market model. The transient

limitations of frequency for making a competitive market between different Demand Response Aggregators (DRA) are considered to provide an AS for producing CR. One of the characteristics of renewable energy inverter generation is that it is highly sensitive to the transient behaviors of the power system. If there is a large contingency, the frequency will drop, and the inverters will respond by shutting off; further decreasing available generation, and exacerbating the contingency. With a large enough presence of inverter-based generation, the effect of a system-wide failure could be catastrophic. Thus, AS become even more important.

The methods described in this study not only guarantee transient constraints of frequency in contingencies by supplying contingency reserve ancillary services by demand response, but also can make profit for both generation company (GENCO) and DRAs. Additionally, the available capacity of the generators can be used more efficiently for power production which they were designed for and not CR; cutting costs, and reducing pollution. In this study, the probability of two nearly simultaneous independent faults or failures is generally assumed to be so small that such events do not deserve to be considered. As a model for the worst case of contingency, case $N-1$ has been designed to simulate losing the biggest generator in the system. Section II describes the power control system used to regulate the system frequency. Section III represents the proposed methodology calculate CR cost and the creation of a market to allow the DRAs to participate in AS. Section IV includes a standard case study (IEEE-24 bus model) and the results after applying the proposed method. Closing remarks can be found in section V.

II. POWER GRID FREQUENCY CONTROL

In calculating the cost of CR, we carefully considered the requirement of the power system to remain within the allowable range of frequency. During contingencies or faults (like the loss of a generator), the grid frequency drops. When we consider a generator, when there is an imbalance between mechanical power and load, the frequency changes. Torque can either accelerate the rotating mass of the generator or be converted into electrical energy. In general, to maintain a constant angular velocity, of course the acceleration must be zero. In order for the acceleration to be zero, the mechanical torque input must be completely converted to electrical energy. Any imbalance would translate into angular acceleration of the rotating generator mass and therefore a change in electrical frequency. This dynamic relationship is modeled using the swing equation (1). This model is usually representative of just one generator, but for the purposes of microgrid, the aggregate behavior of the system is able to be modeled by combining the individual components into an equivalent representation.

$$\frac{2H}{\omega_s} \frac{d^2 \Delta \delta}{dt^2} + D \frac{d \Delta \delta}{dt} + P_s \Delta \delta = 0 \quad (1)$$

Where D is damping torque which can be determined either from design data or by test and P_s is synchronization coefficient. δ is electrical power angle (electrical radian) and ω_s is electrical angular velocity. H is the per-unit inertia constant (second); related to the moment of inertia of the rotating masses within the system [43, 44]. In grids where there is a high penetration of renewable energy generation, the actual mass of physical rotating masses is decreased and therefore the moment of inertial is also decreased (reflected in the value of H) which causes the entire system to be more sensitive to imbalances and exacerbating frequency droop. The value of H depends on the size and type of synchronous machine. Frequency changes much less in large interconnected systems with more rotating mass than in smaller isolated systems [44]. Fig. 1 shows a block diagram of the method used to control generator speeds in response to changes in frequency.

Figure 1: Block diagram of load frequency control

Changing of the load $\Delta P_L(s)$ has an effect on the change in output frequency $\Delta \Omega(s)$. The magnitude of the change in

frequency compared to the change in load is can be expressed as shown in equation (2):

$$\frac{\Delta\Omega(s)}{-\Delta P_L(s)} = \frac{(1 + \tau_g s)(1 + \tau_T s)}{(2Hs + D)(1 + \tau_g s)(1 + \tau_T s) + 1/R} \quad (2)$$

Where τ_g and τ_T are the governor and turbine time constants, which determine the relative effect on frequency to changes in power. D is expressed as percent change in load divided by percent change in frequency (for frequency sensitive loads). R is droop or speed regulation (in percent). In a microgrid with an equivalent swing equation, it can be supposed that losing generation is equivalent to increasing the load. Thus transient and dynamic behaviors of the grid frequency can be analyzed using equation (2). Deviation of the steady state frequency can be obtained from equation (3):

$$\Delta\omega_{ss} = (-\Delta P_L) \frac{1}{D + 1/R} \quad (3)$$

If there are several generators with governor speed regulations $R_1, R_2, \dots, R_n$, equation (3) can be rewritten as:

$$\Delta\omega_{ss} = (-\Delta P_L) \frac{1}{D + 1/R_1 + 1/R_2 + \dots + 1/R_n} \quad (4)$$

In the developing modern power grid there has been a steady increase in the presence of grid-tied photovoltaic inverter systems. These power generating systems are designed to shut down in response to grid input frequencies outside of the normal range as a safety feature. They come with electronics sensitive to signal frequency variation; designed to shut off under abnormal frequency conditions. In the case of a contingency event, where grid frequency is affected, there is risk of losing the power generated by these inverter systems. As this happens, the frequency of the system is further affected and system imbalances are exacerbated. Table 1 shows frequency settings of inverters in different ranges of transient frequencies based on IEEE 1547 standard [45].

Table 1: Standard inverter operating frequency ranges. IEEE 1547 [45]

IEEE Designation	OFR2	OFR1	NORH	NORL	UFR1	UFR2
Frequency Range (Hz)	>62	60.5-62	60-60.5	58.5-60	57-58.5	<57
Mode	Cease	Moment	Normal	Normal	Mand.	Trip
Ride Through (s)	-	300	Infinite	Infinite	300	-
Trip (s)	<=0.160	301	Infinite	Infinite	301	0.16

III. METHODOLOGY

The methods for calculating profits of the GENCO and DRAs as a result of participation in the AS market are explained in subsection C below. CR is purchased directly from DRAs as clients. In order to complete the calculations we must first determine the price at which the GENCO would offer to purchase the amount of CR which would be sufficient to maintain security (Subsection A), independently of DR. This price is determined through OPF. The OPF constraints can be updated based on the availability of frequency regulation resources such generating units, interruptible load as well as DR. Therefore, OPF is executed to find the optimal allocation of each unit and also find the cost curve of procuring DR. Subsection B models the DRAs role in the market and describes their required functionality.

A. CR cost of GENCO using OPF

The first stage of the proposed method is to find the cost which GENCO must pay to maintain provisional AS (in particular CR) considering transient limitations of the frequency. The initial cost of CR is theoretically maximized sufficiently to correct the single worst case contingency event ($N-1$) - i.e. failure of the highest capacity generator. Considering IEEE 1547 standard [45], the key transient parameters of the frequency are: undershoot, undershoot time, and settling time. Fig. 2 illustrates the overall concept of the method. The system begins to act at the start of a contingency event. For illustrative purposes, we assume worst-case-scenario event $N-1$ or the loss of the largest generator in the plant. In order to prevent failsafe systems from shutting off distributed generation of inverters, mitigation of frequency droop below 57 Hz must be provided by traditional means of

spinning reserve in order to bring the grid back to 57 Hz within the allotted 0.16s. It is at this point that we introduce the system for providing the rest of the rest of the AS required for frequency recovery through DR. First the amount of DR required is calculated and a cost curve is generated for this amount of AS for the GENCO using OPF. The GENCO then sends out an offer to the DRAs to purchase DR for AS. There are two distinct price curves, one is for faster DR to recover frequencies from 57-58.5 Hz and slower DR to recover from 58.5-60 Hz. Faster DR is valued at a higher rate. At this point, the market is open for DRAs to bid to fill the GENCO offers. The market is cleared with the purchase of DR as AS until either the entire amount of DR is used, the contingency is over, or the bids from the DRAs exceed the offer from GENCO. Bi-directional communication is maintained between DR resources and the aggregator through means of existing network infrastructures. The GENCO cost curve algorithm (Fig. 3) and GENCO market algorithm (Fig. 4) show the details of how this method is applied to obtain the remaining AS through DR. The purchase of AS from the DR market is optimized through these methods to minimize the costs of operation and maximize social welfare.

Fig. 3 shows the algorithm for determining CR cost curve for GENCO. In the event of an N-1 contingency, the transient parameters of frequency and new inertia are calculated. If the overshoot is less than 3 Hz, IEEE standards leave 300s to clear the fault. If it is greater than 3Hz, IEEE standards leave 0.16s to clear the fault. If the fault is not cleared during this period, the inverter-based generators are tripped off. DR is not fast enough to increase the frequency to 57Hz during 0.16s thereby maintaining functionality independently. GENCO controls the only generating capabilities able to recover the grid frequency to at least 57Hz within the time frame required; once the quick response of the generator reserve brings the frequency back to 57Hz. DRAs may compete to provide AS to increase the grid frequency back to 60Hz from there. Thus, GENCO and DR each contribute to the total increase in frequency. After determining the GENCO and DR's contributions, an OPF is performed for the GENCO in order to find the new available capacities of generators after providing the necessary AS contribution. The remaining AS for CR should be supplied by DR from the nascent market. The starting point of CR cost curve is the point at which the grid frequency is recovered to at least 57Hz- i.e. the cost of the GENCO's initial CR requisite. Clearly, if frequency remains above 57Hz after the *N-1* contingency event, the CR cost includes only non-emergency reserve which can be supplied by DR.

Given the initial point of the cost curve, the remaining values may be found by partitioning the range of frequencies which DR is responsible to regulate over. Let the range (57-60 Hz) be split into M sections (equal or unequal sections). In each section, equation (2) calculates required power (ΔP) which should be supplied by GENCO to increase the frequency as much as Δf . In each section, with increasing power, the inertial constant (H) changes. The calculated CR cost in each section is equal to the marginal cost of the cheapest available generator at that moment which is calculated by running OPF in each section. Based on the IEEE standard (Table 1), if the frequency of the grid is between 57 and 58.5 Hz, the required power must be supplied within a timeframe of less than 300 seconds or the inverter-based generation that is sensitive to frequency will trip off in response. The last point of the curve (M_{th} point) is the only one where optimal grid frequency conditions may be realized. Finally, plotting the CR cost as a function of frequency, while respecting the constraints produces the CR cost curve.

Figure 2. Demand response market implementation for open trading of ancillary services

Figure 3. GENCO cost curve algorithm. Determination of the CR cost curve for input into GENCO market algorithm

B. Forming DR market

The CR cost curve constructed previously outputs GENCO's offer price for CR generation. In order to utilize DR to provide counter bids for provided services we construct a market for trading DR directly as a source of AS, it is assumed that G demand response aggregators, each holding contracts with an unspecified number of buildings, participate in the market directly providing DR from its own pooled resources. Fig. 2 illustrates the participation on both sides of the market.

Fig. 4 represents the GENCO market algorithm which is the method by which the market is cleared in a manner which works toward maximizing profit for all participants and system efficiency. Remember that in the GENCO cost curve algorithm we divided the total range of frequency recovery into M sections. In the GENCO market algorithm, we start at index $k=0$ and work our way up to index M using the calculated price for each section of frequency recovery as a condition by which we base decisions. Recall that b was the point at which the divisions of frequency recovery were split between faster and slower demand response price schemes. All sections below 58.5 Hz fall into the faster category while those greater than 58.5 Hz fall into the slower and less valuable category. While k is less than b , we use the faster demand response algorithm (FDRA) to determine the DRA bid. If this bid price is below the cost of the GENCO to provide AS through spinning reserve, the GENCO will purchase the DR from the DRA, if it is greater, the GENCO will provide its own AS. Each section of frequency recovery is handled by incrementing k for every step. Once k is greater than b , we use the slower demand response algorithm (SDRA) to determine the DRA bid. Once the algorithm has cleared each of M sections, the entire range of frequency recovery has been accounted for. The market parameters are output and profit for DRAs and GENCO are tabulated with the amount of AS traded in the market.

Based on IEEE 1547 standard, AS for CR sufficient to recover grid frequency from 57-58.5Hz should be supplied less than 300 seconds after the contingency event to prevent inverter safety shut off and exacerbation of frequency instability. Each DRA divides its resources into two distinct classes depending on time required to deploy. DRAs can manage and categorize loads of houses based on the contracts, consumers' desired levels of comfort, and essential shading levels. Thus, a given DRA suggests two programs in the market: a faster demand response program (FDRP) and a slower demand response program (SDRP). Dependent on the priority levels of the loads, the faster demand response loads will include those which are less time critical and can be shed first. For example, water heaters can be the first priority loads to be shed and refrigerators can be considered as time critical and shed last; with values also reflected in bid price. This effect can be visualized in the step nature of the bid price in the graphs illustrated in Fig. 8 in the test case and simulation. The algorithm depicted in Fig. 4 shows the steps of the second stage of the proposed method. FDRPs try to increase the grid frequency from 57 to 58.5Hz and SDRPs continue to increase the frequency thereafter to 60Hz, with G aggregators that bid prices for FDRP: $F_1^{DR,fast}, F_2^{DR,fast}, \dots, F_G^{DR,fast}$ and for SDRP: $F_1^{DR,slow}, F_2^{DR,slow}, \dots, F_G^{DR,slow}$ (\$/MW).

Figure 4. GENCO market algorithm. Determination for purchase of demand response for ancillary services to maximize profit and efficiency

In the faster demand response zone, at each point of the cost curve, the market price of AS for CR ($price_{fast}^{CR}$) is the minimum of the bids by DRAs if it is less than the GENCO cost for CR:

$$price_{fast}^{CR} = \min\{C^{CR}, F_1^{DR,fast}, F_2^{DR,fast}, \dots, F_G^{DR,fast}\} \quad (5)$$

$$\text{s.t.} \quad \sum_{k=1}^b \Delta q_{k,g}^{DR,fast} \cdot \alpha_{k,g}^{fast} \leq q_{g,\max}^{DR,fast} \quad g = 1, 2, \dots, G \quad (6)$$

$$\sum_{k=1}^b \sum_{g=1}^G \Delta q_{k,g}^{DR,fast} \cdot \alpha_{k,g}^{fast} = q_{fast}^{DR} \quad (7)$$

Similarly, in the slower demand response zone, the market price of AS for DR ($price_{slow}^{CR}$) is:

$$price_{slow}^{CR} = \min\{C^{CR}, F_1^{DR,slow}, F_2^{DR,slow}, \dots, F_G^{DR,slow}\} \quad (8)$$

$$\text{s.t.} \quad \sum_{k=b+1}^M \Delta q_{k,g}^{DR,slow} \cdot \alpha_{k,g}^{slow} \leq q_{g,\max}^{DR,slow} \quad g = 1, 2, \dots, G \quad (9)$$

$$\sum_{k=b+1}^M \sum_{g=1}^G \Delta q_{k,g}^{DR,slow} \cdot \alpha_{k,g}^{slow} = q_{slow}^{DR} \quad (10)$$

$$\text{and} \quad q_{fast}^{DR} + q_{slow}^{DR} = q^{DR} \quad (11)$$

Where C^{CR} is the price offer by GENCO as the cost offer CR (\$/MW). $\Delta q_{k,g}^{DR,fast}$ ($\Delta q_{k,g}^{DR,slow}$) is the energy quantity provided by the g^{th} aggregator in the k^{th} section of the CR cost curve partition (MW). $q_{g,\max}^{DR,fast}$ ($q_{g,\max}^{DR,slow}$) are the maximum capacities of the g^{th} aggregator in the FDRP and the SDRP (MW). $\alpha_{k,g}^{fast}$ ($\alpha_{k,g}^{slow}$) is a participation factor of the g^{th} aggregator in the k^{th} section of the CR cost curve partition. If it participates, its number is 1 and if it doesn't participate, its number is 0. Equations (12) and (15) present that the market price is the minimum of the offered process by DRAs and utility cost for faster and slower demand response programs, respectively. Conditions provided in equations (13) and (16) guarantee the available DR resources in the DRAs (based on the collected data from communication devices). Equalities in equations (14) and (17) guarantee that all the required DR can be provided by aggregators to regulate the frequency (if there are enough DR resources available). Constraints (13) and (16) require that the total energy provided by the g^{th} aggregator that is distributed over multiple intervals does not exceed its total capacity. q^{DR} is the total energy quantity required of AS for CR which is to be supplied by DR (MW)- i.e. the sum of the total energy quantities to be supplied by DR through FDRP and SDRP: q_{slow}^{DR} and q_{fast}^{DR} . The b^{th} section in the partition of the CR cost curve is the boundary separating faster and slower demand response zones. M is the number of sections in the partition of the CR cost curve.

In competition between the aggregators, the winner will be that which bids the minimum price if it has sufficient capacity available to participate in the AS market, otherwise it is replaced by the next cheapest DRA.

C. Calculations of profit

The DR devices availability is determined by the measurements across the distribution grid. An example of such devices are Grid Interactive Water Heaters (GIWH) which send the temperature and status of water heater and can be remotely controlled via utility or third part aggregator [46, 47]. After deciding which aggregator(s) should participate for different parts of cost curve, the GENCO profit can be obtained from the following equations:

$$PR_{genco}^{fast} = \sum_{k=1}^b \Delta q_k \cdot (C^{CR}(q_k)) \quad (12)$$

$$- \sum_{k=1}^b \sum_{g=1}^G \alpha_{k,g}^{fast} \cdot \Delta q_k \cdot F_g^{DR,fast}(q_k))$$

$$PR_{genco}^{slow} = \sum_{k=b+1}^M \Delta q_k \cdot (C^{CR}(q_k)) \quad (13)$$

$$- \sum_{k=b+1}^M \sum_{g=1}^G \alpha_{k,g}^{slow} \cdot \Delta q_k \cdot F_g^{DR,slow}(q_k))$$

Where PR_{genco}^{fast} and PR_{genco}^{slow} are the profit of GENCO in FDRP and SDRP, respectively (\$). Parameter of $C^{CR}(q_k)$ is the CR cost corresponding to quantity of q_k . Parameter of Δq_k is the shaded load by aggregators between k^{th} and $(k+1)^{th}$ section of CR cost curve. ($\Delta q_k = q_{k+1} - q_k$). The first terms of equations (19) and (20) are CR cost in GENCO side (\$) and the second terms are the money that GENCO pays to aggregators for AS (\$). The total profit of GENCO is:

$$PR_{genco}^{tot} = PR_{genco}^{fast} + PR_{genco}^{slow} \quad (14)$$

The profit corresponding to DRAs can be obtained from the following equations.

$$PR_{DRA,g}^{fast} = \sum_{k=1}^b \alpha_{k,g}^{fast} \cdot \Delta q_k \cdot F_g^{DR,fast}(q_k)) \quad (15)$$

$$PR_{DRA,g}^{slow} = \sum_{k=b+1}^M \alpha_{k,g}^{slow} \cdot \Delta q_k \cdot F_g^{DR,slow}(q_k)) \quad (16)$$

Where $PR_{DRA,g}^{fast}$ and $PR_{DRA,g}^{slow}$ are the profits of g^{th} aggregator in FDRP and SDRP, respectively (\$). The total profit of g^{th} aggregator is:

$$PR_{DRA,g}^{tot} = PR_{DRA,g}^{fast} + PR_{DRA,g}^{slow} \quad (17)$$

IV. TEST CASE AND SIMULATION RESULTS

We chose the case study IEEE 24-bus model for a test case scenario and the proposed method was applied to it in order to demonstrate the provision of AS for CR using DR. Fig. 5 shows the schematic of IEEE-24 bus model with the locations of generators, loads, and DRAs. Technical data of the generation units are available in table 2. The objective function (5) minimizes the total generation cost where the cost for each generator's real power output is given by a second order polynomial term

$$Cost^{gen}(P_g) = \sum_{i=1}^N \eta \cdot P_{g,i}^2 + \beta \cdot P_{g,i} + \gamma \quad \text{where } N \text{ is the number of generators } P_g \text{ is the generated active power. The cost}$$

coefficients (η, β, γ) are selected from the MATPOWER package. The parameters related to control loop model of the grid are:

$$\tau_g = 0.2s, \tau_T = 0.5s, D = 0.8, R = 0.05 \text{ per unit}, H = 5s$$

And the open-loop transfer function will be:

$$\frac{\Delta \Omega(s)}{-\Delta P_L(s)} = \frac{0.1s^2 + 0.7s + 1}{s^3 + 7.08s^2 + 10.56s + 20.8} \quad (18)$$

Figure 5. IEEE-24 bus model with the locations of generators, loads, and DRAs

Table 2. Technical data for generation units of IEEE 24-bus standard model

Node No.	Real power output: P_g (MW)	$P_{\max}$ (MW)	$P_{\min}$ (MW)	$Cost^{gen}(P_g) = \eta \cdot P_g^2 + \beta \cdot P_g + \gamma$		
				η	β	γ
1	2 x 10	20	16	0.3300	75.0000	400.6849
1	2 x 76	76	15.2	0.0141	16.0811	212.3076
2	2 x 10	20	16	0.3300	75.0000	400.6849
2	2 x 76	76	15.2	0.0141	16.0811	212.3076
7	3 x 80	87	25	0.0527	43.6615	781.5210
13	3 x 95.1	170	69	0.0072	48.5804	832.7575
15	5 x 12	12	2.4	0.3284	56.5640	86.3852
15	155	155	54.3	0.0083	12.3883	382.2391
16	155	155	54.3	0.0083	12.3883	382.2391
18	340	340	100	0.0002	4.4231	395.3749
21	340	340	100	0.0002	4.4231	395.3749
22	6 x 50	50	10	0	0.0010	0.0010
23	2 x 155	155	54.3	0.0083	12.3883	382.2391
23	350	350	140	0.0049	11.8495	665.1094

The $N-1$ contingency includes loss of the largest generator with capacity of 350MW located in bus 23. Based on the algorithm of Fig. 3, the first step is to calculate the GENCO and DR's contribution in AS for CR and to find the starting point of CR cost curve. In the mentioned case study GENCO and DR's contribution are 282.9 and 67.1 MW, respectively. Fig. 6 shows the transient frequency at the starting point of the CR cost curve before using the market for AS which the overshoot is less than 3Hz. After the emergency CR (282.9 MW) had been supplied by GENCO to restore the grid frequency above 57Hz, algorithms of Fig. 3 and 4 were performed to determine how DR could then be used to affect the remaining CR.

Figure 6. Transient frequency at the starting point of the CR cost curve

Based on the DR's contribution for AS, the market should be formed only for 67.1 MW. After emergency CR was applied to bring grid frequency above 57Hz, this marked the starting point of the CR cost curve at which the new available capacities of the generators were obtained, from which the points of the CR curve were determined using OPF. Fig. 7 shows the cost of CR which GENCO should pay as an AS.

Figure 7. Cost of CR which GENCO should pay as an AS

The red vertical line shows the border between the zones that should be supplied by FDRP and SDRP, based on the IEEE 1547 standard. It means that 17.11 MW of the load should be shaded in FDRP less than 300 seconds after the contingency. In this case study, it is supposed that there are two aggregators in buses 15 and 18 with demand of 317 and 333 MW, respectively. The availability of the DR sources are obtained using communication devices based on the data measurement in houses [47]. Each of which have both a FDRP and SDRP for their covered house loads. Fig. 8 demonstrates the bid price for DR by two aggregators in FDRP and SDRP, respectively.

Figure 8. Bid price for DR by two aggregators in FDRP and SDRP

Fig. 9 shows the participation factor of DRAs in both FDRP and SDRP. These results show the competition between these two aggregators and contribution of them in order to provide AS for CR in the market. Fig. 10 shows the aggregate quantity of the shed load by DRAs in the market.

Figure 9. Participation factor of DRAs in both FDRP and SDRP

Figure 10. Aggregate quantity load shed by DRAs

The contribution of the DRAs for load shedding are 38.08 and 29.02 MW for the first and second DRAs, respectively. The profit of GENCO and DRAs are:

$$PR_{genco}^{tot} = 1225\$$$

$$PR_{DRA,1}^{tot} = 1372 \$$$

$$PR_{DRA,2}^{tot} = 1200\$$$

V. CONCLUSIONS

In this paper, a method was proposed to determine the value for demand response as an ancillary service to provide contingency reserve using a market model. The method minimizes the cost of ancillary services provided by demand response, maximizes social welfare, and maintains grid stability by mitigating frequency transients to an operating range within industry standards. The IEEE 24-bus model was used to demonstrate the application of the method in the event of the loss of the largest generator in the system. Simulated results showed the cost differential of frequency droop mitigation using demand response compared to conventional generation for ancillary service using the proposed market model. The model included multiple aggregators competing for faster and slower demand response programs.

The proposed method is intended for use in grid systems which are experiencing or would have an increased ratio of renewable generation and frequency sensitive technologies, such as inverters, that may be prone to tripping during a contingency

event. The reduction in system inertia during a contingency event requires alternative economically viable solutions to provide ancillary services and spinning reserve. The simulations in this work clearly show that the proposed methods for providing ancillary service through demand response has a basis for being both economically viable and ensuring system security for credible contingencies.

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