Qualification and Quantification of Reserves in Power Systems Under High Wind Generation Penetration Considering Demand Response

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Abstract—The presence of high levels of renewable energy resources (RES) and especially wind power production poses technical and economic challenges to system operators, which under this fact have to procure more ancillary services (AS) through various balancing mechanisms, in order to maintain the generation-consumption balance and to guarantee the security of the grid. Traditionally, these critical services had been procured only from the generation side, yet the current perception has begun to recognize the demand side as an important asset that can improve the reliability of a power system, offering notable advantages. In this study, a two-stage stochastic programming model, representing the day-ahead market clearing procedure on an hourly basis and the actual minute-to-minute operation of the power system, is developed comprising different services that specifically address various disturbance sources of the normal operation of a power system, namely intra-hour load variation, intra-hour wind variation, as well as generating unit and transmission line outages.

Index Terms—Ancillary services, contingency reserves, demand response, load-following reserves, stochastic programming.

NOMENCLATURE

A. Indices and Sets

\begin{align*}
& \mathcal{F} & \text{Steps of the marginal cost function of unit } i. \\
& \mathcal{I} & \text{Generating units.} \\
& j_1(\mathcal{J}_1) & \text{Load-serving entity 1 (LSE1).} \\
& j_2(\mathcal{J}_2) & \text{Load-serving entity 2 (LSE2).} \\
& r(\mathcal{R}) & \text{Inelastic loads.}
\end{align*}

B. Variables

\begin{align*}
& b_{i,f,t_1} & \text{Power output scheduled from the } f^{th} \text{ block by unit } i \text{ in period } t_1 (\text{MW}). \\
& \text{CA}_{i,t_2,s} & \text{Additional cost in period } t_2, \text{ in scenario } s, \text{ incurred due to change in commitment status of unit } i (\text{€}). \\
& f_{l,t_2,s} & \text{Power flow through line } l, \text{ in period } t_2, \text{ in scenario } s (\text{MW}). \\
& L_{\text{shel}}^{r,t_2,s} & \text{Load shed in from inelastic load } r, \text{ in period } t_2, \text{ in scenario } s (\text{MW}). \\
& \text{LSE}_1^{\text{load},j_1,t_1} & \text{Total down reserve deployed from LSE1 } j_1, \text{ in period } t_2, \text{ in scenario } s (\text{MW}). \\
& \text{LSE}_1^{\text{load},x,j_1,t_2,s} & \text{Load-following down reserve } (x = \{ \text{load, wind} \}) \text{ deployed from LSE1 } j_1, \text{ in period } t_2 \text{ in scenario } s (\text{MW}). \\
& \text{LSE}_1^{\text{DN},j_1,t_1} & \text{Total down reserve scheduled from LSE1 } j_1, \text{ in period } t_1 (\text{MW}). \\
& \text{LSE}_1^{\text{DN},x,j_1,t_1} & \text{Load-following spinning down reserve } (x = \{ \text{load, wind} \}) \text{ scheduled from LSE1 } j_1, \text{ in period } t_1 (\text{MW}). \\
& \text{LSE}_1^{\text{UP},j_1,t_1} & \text{Total up reserve deployed from LSE1 } j_1, \text{ in period } t_2, \text{ in scenario } s (\text{MW}). \\
& \text{LSE}_1^{\text{UP},x,j_1,t_1} & \text{Load-following up reserve } (x = \{ \text{load, wind} \}) \text{ deployed from LSE1 } j_1, \text{ in period } t_2 \text{ in scenario } s (\text{MW}). \\
& \text{LSE}_1^{\text{UP},x,j_1,t_1} & \text{Total up reserve scheduled from LSE1 } j_1, \text{ in period } t_1 (\text{MW}). \\
& \text{LSE}_1^{\text{UP},x,j_1,t_1} & \text{Load-following spinning up reserve } (x = \{ \text{load, wind} \}) \text{ scheduled from LSE1 } j_1, \text{ in period } t_1 (\text{MW}).
\end{align*}
<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>LSE (_2)</td>
<td>Contingency spinning down reserve deployed from LSE (_2) in period (t_2) in scenario (s) (MW).</td>
</tr>
<tr>
<td>LSE (<em>2) (</em>{DN,con})</td>
<td>Contingency spinning down reserve scheduled from LSE (_2) in period (t_1) (MW).</td>
</tr>
<tr>
<td>LSE (<em>2) (</em>{real})</td>
<td>Actual consumption of LSE (_1) in period (t_2) in scenario (s) (MW).</td>
</tr>
<tr>
<td>LSE (<em>2) (</em>{sch})</td>
<td>Scheduled demand from LSE (_2) in period (t_1) constrained by LSE (<em>2) (</em>{min}) and LSE (<em>2) (</em>{max}).</td>
</tr>
<tr>
<td>LSE (<em>2) (</em>{con})</td>
<td>Contingency spinning up reserve deployed from LSE (_2) in period (t_2) in scenario (s) (MW).</td>
</tr>
<tr>
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</tr>
<tr>
<td>(P_G) (_{i,t_2})</td>
<td>Actual power output of unit (i) in period (t_2) in scenario (s) (MW).</td>
</tr>
<tr>
<td>(P_{sch}) (_{i,t_1})</td>
<td>Power output scheduled for unit (i) in period (t_1) (MW).</td>
</tr>
<tr>
<td>(P_{r}) (_{i,t_1})</td>
<td>Total reserve scheduled from unit (i) in period (t_1) (MW).</td>
</tr>
<tr>
<td>(P_X) (_{i,t_1})</td>
<td>Total reserve scheduled from unit (i) in period (t_1) (MW).</td>
</tr>
<tr>
<td>(P_{X,y}) (_{i,t_1})</td>
<td>Reserve scheduled from unit (i) in period (t_1) (MW).</td>
</tr>
<tr>
<td>(r_x) (_{i,t_2})</td>
<td>Total reserve deployed by unit (i) during period (t_2) in scenario (s) (MW).</td>
</tr>
<tr>
<td>(r_{x,y}) (_{i,t_2})</td>
<td>Reserve deployed from the (f)th block of unit (i) in period (t_2) in scenario (s) (MW).</td>
</tr>
<tr>
<td>(r_G) (_{i,t_2})</td>
<td>Reserve deployed from the (f)th block of unit (i) in period (t_2) in scenario (s) (MW).</td>
</tr>
<tr>
<td>(S_{w,t_2})</td>
<td>Wind spilled from wind farm (w) in period (t_2), in scenario (s) (MW).</td>
</tr>
<tr>
<td>(S_{DC}^1) (_{i,t_1})</td>
<td>Shut-down cost of unit (i) in period (t_1) (€).</td>
</tr>
<tr>
<td>(S_{UC}^1) (_{i,t_1})</td>
<td>Start-up cost of unit (i) in period (t_1) (€).</td>
</tr>
<tr>
<td>(S_{DC}^2) (_{i,t_2})</td>
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</tr>
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</tr>
<tr>
<td>(f^{\min})</td>
<td>Minimum power output of unit (i) (MW).</td>
</tr>
<tr>
<td>(f^{\max})</td>
<td>Maximum power output of unit (i) (MW).</td>
</tr>
<tr>
<td>(P_{call})</td>
<td>Maximum number of calls of LSE (<em>2) (</em>{j_2}).</td>
</tr>
<tr>
<td>(P_{min})</td>
<td>Minimum power output of unit (i) (MW).</td>
</tr>
<tr>
<td>(prob(s))</td>
<td>Probability of wind power scenario (s).</td>
</tr>
<tr>
<td>(RC_{D,LSE2}) (_{j_1,t_1})</td>
<td>Offer cost of spinning down reserve by unit (i) in period (t_1) (€/MWh).</td>
</tr>
<tr>
<td>(RC_{N,LSE2}) (_{j_2,t_1})</td>
<td>Offer cost of nonspinning reserve by unit (i) in period (t_1) (€/MWh).</td>
</tr>
<tr>
<td>(RC_{UP}) (_{i,t_1})</td>
<td>Cost of spinning up reserve by unit (i) in period (t_1) (€/MWh).</td>
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</tbody>
</table>

C. Parameters

- \(A_{n,x}\)
- \(B_{i,f,t_1}\)
- \(B_{l,n}\)
- \(C_{i,f,t_1}\)
- \(D_{sch}^1\)
- \(D_{sch}^2\)
- \(D_{T}^1\)
- \(D_{T}^1\)
- \(E_{\text{req}}\)
- \(f^{\max}\)
- \(L_{C_{i,t_2}}\)
- \(N_{\text{call}}\)
- \(P_{f_{\text{max}}}\)
- \(P_{i_{\text{min}}}\)
- \(\text{prob}(s)\)
- \(\text{RC}_{D,LSE2}\)
- \(\text{RC}_{N,LSE2}\)
- \(\text{RC}_{UP}\)

Node to resource incidence matrix of resource \(x\) (inelastic load, LSE \(_1\), LSE \(_2\), unit or wind farm). Element is 1 if resource \(x\) is located at node \(n\).

- Size of step \(f\) of unit \(i\) marginal cost function in period \(t_1\) (MW).
- Absolute value of the imaginary part of the admittance of line \(l\) (p.u.).
- Marginal cost of step \(f\) of unit \(i\) marginal cost function in period \(t_1\) (€/MWh).
- Scheduled load (first stage) (MW).
- Real-time load (second stage) (MW).
- Minimum down-time of unit \(i\) (first stage) (h).
- Minimum down-time of unit \(i\) (second stage) (min).
- Energy requirement of LSE \(_1\) \(_{j_1}\) (MWh).
- Maximum capacity of line \(l\) (MW).
- Line contingency parameter-0 if line \(l\) is down during period \(t_2\), else 1.
- Maximum number of calls of LSE \(_2\) \(_{j_2}\).

- Maximum power output of unit \(i\) (MW).
- Minimum power output of unit \(i\) (MW).
- Probability of wind power scenario \(s\).
- Offer cost of spinning down reserve by unit \(i\) in period \(t_1\) (€/MWh).
- Offer cost of spinning down reserve by LSE \(_1\) \(_{j_1}\) in period \(t_1\) (€/MWh).
- Offer cost of spinning down reserve by LSE \(_2\) \(_{j_2}\) in period \(t_1\) (€/MWh).
- Offer cost of nonspinning reserve by unit \(i\) in period \(t_1\) (€/MWh).
technical specifications vary from country to country, even from under normal and emergency conditions [7]. AS definitions and quality, reliability, and security of the system operation are met through various mechanisms, in order to ensure that power authorities should procure the required ancillary services (ASs) for energy sources (RES), mainly due to regulatory barriers. Europe has taken little steps [11], although the provision of critical AS from the demand side [10]. Pioneering role in this field, by establishing DR programs that allow the provision of these critical services, especially by introducing the advantages of immediate, statistically reliable response, and also distributed nature.

Thus, relative to the design of AS provision mechanism, resources both on the generation and the demand side should be evaluated in terms of suitability of providing specific services. The operation of the majority of production units is constrained by ramping time, minimum on, and minimum off time limits. On the other hand, most of the loads can respond instantly (e.g., air-conditioning), curtailling their consumption faster than the generation side would increase the power production. Furthermore, it is reported that the reliability related to the response to a signal of a system operator is greater in the case of aggregation of small responsive loads, rather than in the case of fewer number of large generators [8]. Especially, when considering the reliability and balancing mechanisms of a power system under high renewable generation penetration (e.g., wind power production), demand response (DR) has already been proven to be a flexible tool for operators to use [9]. Despite these pros, the implementation of such demand side schemes is not widely spread. Historically, U.S. markets play a pioneering role in this field, by establishing DR programs that allow the provision of critical AS from the demand side [10]. Europe has taken little steps [11], although the provision of these services by DR programs has been recognized as mandatory in order to support greater future integration of renewable energy sources (RES), mainly due to regulatory barriers.

### B. Literature Overview

The topic of qualification and quantification of the appropriate AS to handle the challenging aspects of RES penetration, as well as contingencies, has drawn the attention of various researchers and system operators around the world.

A detailed treatment of the AS that exist in different power systems, in seven different countries, can be seen in [12] and [13]. A tangible demonstration of the capability of loads to provide AS as well as a typology of different AS can be found in [14] and [15]. In [16] and [17], a stochastic security-constrained market-clearing problem is formulated, where line and generator outages are considered through a preselected set of random contingencies, determining the reserves by penalizing the expected load not served. In [18], a two-stage stochastic programming model is developed to evaluate the economic impact of reserve provision under high wind power generation penetration. In [19], a two-stage stochastic model is presented, including dispatchable DR providers, used to meet the security constraints of the system. In [20], a day-ahead market structure is presented, where demand side participates in contingency
reserve provision by bidding an offer curve that represents the cost of making the loads available for curtailment.

A comprehensive evaluation of DR activities for AS can be seen in [21]. Apart from the commonly met AS types, a new type was recently proposed by Midwest ISO [22] and California ISO [23] as flexible ramping products to increase the robustness of the load following reserves under uncertainty, such as high solar and wind power ramping events.

Providing AS in a market operation first requires solving a unit commitment (UC) problem. Based on a literature survey on the topic of solving UC problems, a great number of techniques can be found applied in different studies. Among them, meta-heuristic approaches including evolutionary algorithms, particle swarm optimization, tabu search, and simulated annealing as well as their hybrids, have been extensively used for the solution of the UC problem [24]–[30]. Artificial intelligence methods such as fuzzy and expert systems and neural networks have also been used [31]–[32]. Priority list methods [33] were among the first methods applied for the solution of the UC problem.

A last branch of techniques utilized for dealing with the UC problem can be given as mathematical programming methods. Among them, Lagrangian relaxation is proposed in [34] for a transient stability-constrained network structure. The mentioned Lagrangian relaxation method and its improved versions are also employed in [35]–[37]. The combination of Lagrangian relaxation with mixed-integer nonlinear programming (MINLP) is also applied in the literature in [38]. Dynamic programming has also been extensively applied for UC solution in the past [39]. Nowadays, mixed-integer linear programming (MILP) is considered as the state of the art for the UC problem solution. It is almost exclusively employed in modern centralized market clearing engines and has the leading portion in the recent related literature [40]–[42]. A detailed discussion on UC problem solution approaches can be found in [43].

C. Overview of the Study and Contribution

In this paper, a two-stage stochastic programming-based joint energy and reserve market-clearing model within MILP framework is proposed in order to evaluate the required level of reserves in order to tackle with the uncertainty introduced by the increased penetration of wind power generation, intra-hour load variations, line failures, and unit outages that are considered known through a parameter.

The first stage of the model represents the day-ahead market and is cleared on an hourly basis. The second stage is cleared on minute basis (e.g., 10 min) and simulates possible instances of the actual operation of the power system. In order to ensure the system’s reliability, several reserve services are employed. First, load-following reserves procured from conventional units and load serving entities (LSE) under an appropriate framework deal with the minute-to-minute load and wind deviations. The power unbalance caused by contingencies related to transmission lines and generators is handled through spinning and nonspinning reserves from online and offline generating units as well as from LSE that are committed to alter their consumption in order to provide emergency reserves. The explicit novel contribution of this paper is the consideration of all the aforementioned resources and operating conditions of a power system in a single joint energy and reserve day-ahead clearing model.

D. Paper Organization

The remainder of this paper is organized as follows. In Section II, the proposed methodology is presented. In Section III, the obtained results are described and discussed. Finally, conclusions derived from the present study are summarized in Section IV.

II. METHODOLOGY

The model consists of two stages as can be seen in Fig. 1, where the first stage represents the day-ahead market and involves variables and constraints that are independent from any specific scenario (here-and-now decisions), while the second stage represents the actual operation of the power system and involves variables and constraints dependent on each scenario (wait-and-see decisions) according to their probabilities of occurrence.

A. Time Granularity

The first stage of the problem is cleared on an hourly basis, while the second stage is cleared on minute basis.

It is common in the literature for the second stage to have the same time granularity as the first one (e.g., [18]). The evaluation
of the second stage in such an intra-hour basis provides a more realistic insight into the problem. The time granularity of the second stage can be changed to any preferred time interval.

B. Reserve Types

In the proposed methodology, the following types of reserves are modeled.

1) Load-following reserves. This type of reserve is employed by both generators and LSE that are committed to provide this service. It consists of synchronized up and down and also nonspinning reserves that are provided by units to balance the intra-hour load and wind deviations. LSE can also provide up and down reserves of this type to the system on a continuous basis. The consumption of these flexible entities can be scheduled in the day-ahead market operation. In the second stage, it can be rescheduled in order to provide load-following reserves. They contribute to the operating cost through their utility value and a cost to schedule the provision of this service.

2) Contingency reserves. In case of a unit or transmission line outage, the deficit of energy is covered by synchronized or nonsynchronized units, or LSE that are committed to provide this service. The LSE that provide this service are considered to be compensated at a cost related with the time they are called to provide this service and are also compensated to be on stand-by.

C. Operation of the Different Types of Loads

In the proposed model, three different types of loads can be identified.

1) Inelastic load. The consumption of this type of load cannot be altered. Though under a very high penalty, the system operator may use involuntary shedding of this type of load in order to satisfy the power balance, as a last resort.

2) LSE that provide load-following reserves. The consumption of this type of load can alter its scheduled consumption within limits in order to respond to wind power fluctuations and intra-hour load deviations.

3) LSE that provide contingency reserves. The scheduled consumption of this load type can be modified in real time in order to respond to contingencies. Its participation in reserve provision is subject to several constraints. In this paper, it is considered that there are limited times of calls during the horizon and that every call has a specific maximum duration. More detailed behavior (e.g., minimum time between two calls) and contract types can be easily integrated within the proposed methodology.

D. Contingency Incorporation

In this study, it is considered that the transmission line and unit contingencies are perfectly known through a parameter, respectively. When a contingency of a unit occurs, it is assumed that its power output is instantly set to zero. Because of the short length of the horizon under examination, it is assumed that once a unit trips, it stays in failure condition until the end of the study horizon.

When a line failure occurs at some time interval, its power transfer capability is set to zero. It is consider that a line may be repaired within the study horizon.

E. Mathematical Formulation

1) Objective Function:

\[
C'_{i,f,t_2} = \frac{C_{i,f,t_1}}{60} \cdot \Delta T \quad \forall i, t_2 \in T_{in}^2, t_1, f
\]

\[
\lambda^{\text{LSE1'}}_{j_1,t_2} = \frac{\lambda_{j_1,t_1}}{60} \cdot \Delta T \quad \forall j_1, t_2 \in T_{in}^2, t_1.
\]

The objective is to minimize the total expected cost of the system’s operation. In (1), the first line describes the start-up and shut-down costs of the units and the cost of energy production. The second line expresses the cost of scheduling reserves from the generation side. The third line considers the utility of the LSE1 load. The next two lines stand for the cost of scheduling reserves from the LSE. The second stage of the formula stands right below and is clearly dependent on the occurrence probability of each scenario. The seventh line considers the additional cost from a start-up/shut-down that was not

Expected cost

\[
= \sum_{t_1} \sum_i \left( \text{SUC}_i^{1,t_1} + \text{SDC}_i^{1,t_1} \right) + \sum_i \sum_{f} \left( C_{i,f,t_1} \cdot b_{i,f,t_1} \right) + \sum_i \left( \text{RC}_{i,t_1}^{\text{UP}} \cdot F_{i,t_1}^{\text{UP}} + \text{RC}_{i,t_1}^{\text{DN}} \cdot F_{i,t_1}^{\text{DN}} + \text{RC}_{i,t_1}^{\text{NS}} \cdot F_{i,t_1}^{\text{NS}} \right)
\]

\[
- \sum_{j_1} \left( \lambda_{j_1,t_1} \cdot \text{LSE}^{1\text{sch}}_{j_1,t_1} \right) + \sum_{j_1} \left( \text{RC}_{j_1,t_1}^{\text{UP\text{LSE}1}} \cdot \text{LSE}^{1\text{UP}}_{j_1,t_1} + \text{RC}_{j_1,t_1}^{\text{DN\text{LSE}1}} \cdot \text{LSE}^{1\text{DN}}_{j_1,t_1} \right)
\]

\[
+ \sum_{j_2} \left( \text{RC}_{j_2,t_1}^{\text{UP\text{LSE}2}} \cdot \text{LSE}^{2\text{UP\text{con}}}_{j_2,t_1} + \text{RC}_{j_2,t_1}^{\text{DN\text{LSE}2}} \cdot \text{LSE}^{2\text{DN\text{con}}}_{j_2,t_1} \right) + \sum_s \text{prob}(s)
\]

\[
\left\{ \sum_{t_2} \left( \text{CA}_{i,t_2,s} \right) + \sum_i \sum_{f} \left( C_{i,f,t_2} \cdot rG_{i,t_2,s,f} \right) + \sum_{j_1} \left( \lambda_{j_1,t_2} \cdot (\text{LSE}^{1\text{up}}_{j_1,t_2,s} - \text{LSE}^{1\text{dn}}_{j_1,t_2,s}) \right)
\]

\[
+ \sum_{j_2} \left( \lambda_{j_2,t_2} \cdot \psi_{j_2,t_2,s} \right) + \sum_w \left( \frac{\text{V}^{\text{spill}}_{w,t_2}}{60} \cdot \Delta T \cdot S_{w,t_2,s} \right) + \sum_r \left( \frac{\text{V}^{\text{LL}}_{r,t_2}}{60} \cdot \Delta T \cdot r_{\text{shed}}_{r,t_2,s} \right) \right\}
\]

(1)
scheduled and the cost of reserves implemented as energy. The eighth and ninth lines describe the cost of procuring reserve services from LSE. The last line considers the wind spillage and involuntary load shedding during the actual operation of the system.

Equations (2) and (3) adjust the cost of deploying reserves from units and LSE1, respectively. They are needed as the marginal costs; the LSE1 utilities are given in €/MWh, while the actual energy refers to $\Delta T$ min intervals.

2) First Stage Constraints:
   a) Generation limits:
   $$P_{i,t}^{sch} = \sum_{f} b_{i,f,t} \forall i, t_1$$  
   (4)
   $$0 \leq b_{i,f,t} \leq B_{i,f,t} \forall i, f, t_1$$  
   (5)
   $$P_{i,t}^{sch} - P_{i,t}^{DN} \geq P_{i,t}^{min} \cdot u_{i,t}^1 \forall i, t_1$$  
   (6)
   $$P_{i,t}^{sch} + P_{i,t}^{UP} \leq P_{i,t}^{max} \cdot u_{i,t}^1 \forall i, t_1$$  
   (7)

   The generator cost function is considered convex and it is approximated by a step-wise linear function as in [44]. This is enforced by (4) and (5). Constraints (6) and (7) limit the output of a generating unit considering also the scheduled down and up reserves, respectively.

   b) Generator minimum up and down time constraints:
   $$\sum_{\tau=t_1-UT^1+1}^{t_1} y_{i,t}^1 \leq u_{i,t}^1 \forall i, t_1$$  
   (8)
   $$\sum_{\tau=t_1-DT^1+1}^{t_1} z_{i,t}^1 \leq 1 - u_{i,t}^1 \forall i, t_1.$$  
   (9)

   Constraint (8) forces a unit to remain committed for at least UT periods once it starts up, while (9) forces a unit to remain offline for at least DT periods once it is shut-down.

   c) UC logic constraints:
   $$y_{i,t}^1 + z_{i,t}^1 \leq 1 \forall i, t_1$$  
   (10)
   $$y_{i,t}^1 - z_{i,t}^1 = u_{i,t}^1 - u_{i,(t-1)}^1 \forall i, t_1.$$  
   (11)

   Equation (10) states that a unit cannot start-up and shut-down during the same period, while (11) enforces the start-up and shut-down status change logic.

   d) Start-up/shut-down costs:
   $$SUC_{i,t_1} \geq SUC_{i} \cdot y_{i,t_1} \forall i, t_1$$  
   (12)
   $$SDC_{i,t_1} \geq SDC_{i} \cdot z_{i,t_1} \forall i, t_1.$$  
   (13)

   With (12) and (13), the start-up and shut-down costs of the generators are taken into account.

   e) Ramp-up and -down limits:
   $$P_{i,t}^{sch} - P_{i,(t-1)}^{sch} \leq 60 \cdot RU_i \forall i, t_1$$  
   (14)
   $$P_{i,t}^{sch} - P_{i,(t-1)}^{sch} \leq 60 \cdot RD_i \forall i, t_1.$$  
   (15)

   Constraints (14) and (15) consider the effect of the ramp rates that limit the changes in the unit’s output.

   f) Generator side reserve limits:
   $$0 \leq R_{i,t}^{UP} \leq 60 \cdot RU_i \cdot u_{i,t}^1 \forall i, t_1$$  
   (16)
   $$0 \leq R_{i,t}^{DN} \leq 60 \cdot RD_i \cdot u_{i,t}^1 \forall i, t_1.$$  
   (17)

   Constraints (16)–(18) impose a limit in the scheduling of spinning up and down reserves as well as nonspinning reserve from the generating units.

   g) Wind generation limits:
   $$0 \leq W_{w,t}^{sch} \leq W_{w}^{cap} \forall w, t_1.$$  
   (19)

   Equation (19) imposes a limit on the power accepted by each wind farm.

   Unlike the selection made in [18] to consider the upper limit as infinite, here the upper limit is enforced to be equal to the installed capacity of every wind farm.

   h) Market equilibrium:
   $$\sum_{i} P_{i,t_1}^{sch} + \sum_{w} W_{w,t_1}^{sch} = \sum_{j} D_{r,t_1} + \sum_{j} LSE_{sch}^{1} \forall t_1.$$  
   (20)

   In the first stage of the model, the network constraints are not enforced. Thus, the power balance is described by the market equilibrium in (20). Undoubtedly, any market representation can be adopted in the first stage.

   i) Generator side reserves decomposition in services:
   $$R_{i,t_1}^{UP} = R_{i,t_1}^{UP,load} + R_{i,t_1}^{UP,wind} + R_{i,t_1}^{UP,con} \forall i, t_1$$  
   (21)
   $$R_{i,t_1}^{DN} = R_{i,t_1}^{DN,load} + R_{i,t_1}^{DN,wind} + R_{i,t_1}^{DN,con} \forall i, t_1.$$  
   (22)
   $$R_{i,t_1}^{NS} = R_{i,t_1}^{NS,load} + R_{i,t_1}^{NS,wind} + R_{i,t_1}^{NS,con} \forall i, t_1.$$  
   (23)

   Up-spinning reserves, down-spinning reserves, and nonspinning reserves are scheduled in order to maintain the system balance during the actual operation of the power system that is disturbed due to positive or negative load (elastic or inelastic) deviations, wind ramp-ups and -downs, and contingency events. Up-spinning reserves imply the increase in a synchronized unit’s power output, while down-spinning reserves stand for the opposite. Nonspinning reserves are provided by nonsynchronized units as stated by (18). Equations (21)–(23) decompose the unit’s total scheduled up, down, or nonspinning reserves to different services that respond to different factors that can trigger the need of such reserves.

   j) LSE1 consumption, reserves limits, and decomposition in services:
   $$LSE_{min,1}, t_1 \leq LSE_{sch,1}, t_1 \leq LSE_{max,1}, t_1 \forall j_1, t_1.$$  
   (24)
   $$LSE_{1,1}, t_1 = LSE_{1,load,1, t_1} + LSE_{1,wind,1, t_1} \forall j_1, t_1.$$  
   (25)
   $$0 \leq LSE_{1,1}, t_1 \leq LSE_{sch,1}, t_1 - LSE_{min,1}, t_1 \forall j_1, t_1.$$  
   (26)
   $$LSE_{1,1}, t_1 = LSE_{1,load,1, t_1} + LSE_{1,wind,1, t_1} \forall j_1, t_1.$$  
   (27)
0 ≤ LSE1_{j_1, t_1}^{DN} ≤ LSE1_{j_1, t_1}^{max} − LSE1_{j_1, t_1}^{sch} \forall j_1, t_1 \quad \text{(28)}

\sum_{t_1} LSE1_{j_1, t_1} = r_{j_1}^{req} \forall j_1. \quad \text{(29)}

As stated before, demand side can also contribute in reserves. In this study, we consider two types of LSE that are able to provide reserves. LSE of type 1 can provide up and down load-following reserves as stated by (26) and (28), respectively. This type of reserves is further decomposed into reserves that balance the wind deviations and reserves that balance the intra-hour load deviations, a fact that is enforced by (25) and (27), respectively. Constraint (24) enforces that the scheduled LSE1 demand for each period has to respect the limits of its maximum capability of being altered from a nominal value. To ensure that the LSE1 energy needs are fulfilled during the horizon, despite the fact that it may be scheduled for partial curtailment through the horizon, the energy requirements are enforced by (29).

k) LSE2 consumption and reserve limits:

\[ LSE2_{j_2, t_1}^{min} \leq LSE2_{j_2, t_1}^{sch} \leq LSE2_{j_2, t_1}^{max} \forall j_2, t_1 \quad \text{(30)} \]

\[ 0 \leq LSE2_{j_2, t_1}^{UP, \text{con}} \leq LSE2_{j_2, t_1}^{sch} - LSE2_{j_2, t_1}^{min} \forall j_2, t_1 \quad \text{(31)} \]

\[ 0 \leq LSE2_{j_2, t_1}^{DN, \text{con}} \leq LSE2_{j_2, t_1}^{max} - LSE2_{j_2, t_1}^{sch} \forall j_2, t_1. \quad \text{(32)} \]

LSE of type 2 can provide up and down contingency reserves, as stated by (31) and (32), respectively.

Up reserve from the perspective of load has the meaning of consumption reduction, while down reserves stand for a consumption increase. This type of load is not subject to an energy requirement constraint due to the fact that it is paid to be curtailed for a prespecified number of periods.

3) Second Stage Constraints:

a) Network constraints:

\[ A_{w, w}^{\text{net}} \sum_w (WP_{w, t_2, s} - S_{w, t_2, s}) + A_{n, t_1}^{\text{unit}} \cdot \sum_i P_i^{G, t_2, s} \]

\[ - \sum_{l \in L(n=nn)} f_{l, t_2, s} + \sum_{l \in L(n=nn)} f_{l, t_2, s} \]

\[ = A_{n, t_1}^{\text{unit}} \cdot \sum_r (D_{r, t_2}^{2} - L_{r, t_2}^{\text{shed}}) + A_{n, t_1}^{\text{LSE1, real}} \cdot \sum_j LSE1_{j_1, t_2, s} \]

\[ + A_{n, t_2}^{\text{LSE2, real}} \cdot \sum_{j_2} LSE2_{j_2, t_2, s} \forall n, t_2, s \quad \text{(33)} \]

\[ f_{l, t_2, s} = B_l \cdot n \cdot (\delta_{n, t_2, s} - \delta_{n, t_2, s}) \cdot LC_{l, t_2} \]

\[ \forall (n, nn) \equiv l, n, t_2, s \quad \text{(34)} \]

\[ -f_{l, t_2, s} \leq f_{l, t_2, s} \leq f_{l, t_2, s} \forall l, n, t_2, s. \quad \text{(35)} \]

In the second stage of the problem, the network constraints are enforced by (33)–(35). If a line outage occurs, the flow through this line is set to zero.

b) Generation limits:

\[ P_{i, t_2, s}^{G} \geq P_i^{\text{min}} \cdot u_{i, t_2, s} \forall i, t_2, s \quad \text{(36)} \]

\[ P_{i, t_2, s}^{G} \leq P_i^{\text{max}} \cdot u_{i, t_2, s} \forall i, t_2, s. \quad \text{(37)} \]

Through (36) and (37), the minimum and maximum generation limits are also enforced in the second stage of the problem.

c) Ramp-up and -down limits:

\[ P_{i, (t_2-1), s}^{G} - P_{i, t_2, s}^{G} \leq \Delta T \cdot RU_i \forall i, t_2, s \quad \text{(38)} \]

\[ P_{i, (t_2-1), s}^{G} - P_{i, t_2, s}^{G} \leq \Delta T \cdot RD_i + N_1 \cdot (1 - UC_{i, t_2}) \forall i, t_2, s. \quad \text{(39)} \]

As stated before, a \( \Delta T \)-minute time interval is adopted in the second stage of the model. As the ramp-up and -down rates of the units are given in MW/min, from interval to interval during the actual operation, the power output of a unit can change by this rate multiplied by \( \Delta T \). Constraint (39) is relaxed when the unit fails.

d) Generator minimum up and down time constraints:

\[ \sum_{t_2} \frac{t_2 - t_{t_2, s}}{\Delta T} \leq u_{i, t_2, s}^2 \forall i, t_2, s \quad \text{(40)} \]

\[ \sum_{t_2} \frac{z_{i, t_2, s}^2}{\Delta T} \leq u_{i, t_2, s}^2 - 1 \forall i, t_2, s \quad \text{(41)} \]

As the minimum up and down times of a unit are given in minutes for the second stage, they should be divided by the interval length \( \Delta T \) as indicated by (40) and (41).

e) UC logic constraints:

\[ y_{i, t_2, s}^2 + z_{i, t_2, s}^2 \leq 1 \forall i, t_2, s \quad \text{(42)} \]

\[ y_{i, t_2, s}^2 - z_{i, t_2, s}^2 = u_{i, t_2, s}^2 - u_{i, (t_2-1), s}^2 \forall i, t_2, s. \quad \text{(43)} \]

Similar to (10) and (11), constraints (42) and (43) ensure that the logic of UC is preserved.

f) Start-up/shut-down costs:

\[ \text{SUC}_{i, t_2, s}^2 \geq \text{SUC}_i \cdot y_{i, t_2, s}^2 \forall i, t_2, s \quad \text{(44)} \]

\[ \text{SDC}_{i, t_2, s}^2 \geq \text{SDC}_i \cdot z_{i, t_2, s}^2 \forall i, t_2, s. \quad \text{(45)} \]

In the second stage of the problem, (44) and (45) stand for the start-up and shut-down costs of the generators.

g) Wind spillage and load shedding limits:

\[ 0 \leq S_{w, t_2, s} \leq WP_{w, t_2, s} \forall i, t_2, s \quad \text{(46)} \]

\[ 0 \leq L_{r, t_2, s} \leq D_{r, t_2}^2 \forall i, t_2, s. \quad \text{(47)} \]

Equations (46) and (47) enforce that the system operator, at a high cost, can spill available wind production or shed partially inelastic cost, as a last resort to satisfy the power balance under constrained operation of the power system.

4) Linking Constraints: To simplify the mathematical formulation presented below, we should remark at this point the following: the equations that refer to reserve deployment by generating units hold only for units that are not under contingency. Also, as long as there are no contingencies or wind/load deviations, the reserves provided by the demand side are also zero and the relevant equations do not hold.
a) Additional cost due to the change of commitment status of units:

\[ C_{A_{i,t_2,s}} = \sum_{t_2} SUC_{i,t_2,s}^1 - SUC_{i,t_1,s}^1 + \sum_{t_2} SDC_{i,t_2,s}^1 - SDC_{i,t_1,s}^1 \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(48)

In case of a difference occurring in the commitment status, a commitment scheduling change cost is charged through (48).

b) Decomposition and deployment of generation side reserves:

\[ P_{G_{i,t_2,s}} = P_{sch_{i,t_1,s}} + P_{up_{i,t_2,s}} + P_{ms_{i,t_2,s}} - P_{dn_{i,t_2,s}} \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(49)

\[ r_{up_{i,t_2,s}} = P_{up_{i,t_2,s}} + P_{up_{i,t_2,s}} + P_{dn_{i,t_2,s}} \forall i, t_2, s. \]  

(50)

\[ r_{dn_{i,t_2,s}} = P_{dn_{i,t_2,s}} + P_{dn_{i,t_2,s}} + P_{ms_{i,t_2,s}} \forall i, t_2, s. \]  

(51)

\[ r_{ms_{i,t_2,s}} = P_{ms_{i,t_2,s}} + P_{ms_{i,t_2,s}} + P_{ms_{i,t_2,s}} \forall i, t_2, s. \]  

(52)

\[ 0 \leq r_{up_{i,t_2,s}} \leq R_{up_{i,t_1}} \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(53)

\[ 0 \leq r_{dn_{i,t_2,s}} \leq R_{dn_{i,t_1}} \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(54)

\[ 0 \leq r_{ms_{i,t_2,s}} \leq R_{ms_{i,t_1}} \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(55)

Similar to the general (49)–(55) restrictions, the decomposed deployed reserves should be constrained by the corresponding scheduled amount.

c) Decomposition of generation side reserves into blocks:

\[ r_{up_{i,t_2,s}} + r_{ms_{i,t_2,s}} - r_{dn_{i,t_2,s}} = \sum_{f} r_{G_{i,t_2,s,f}} \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(56)

\[ r_{G_{i,t_2,s,f}} \leq B_i \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(57)

\[ r_{G_{i,t_2,s,f}} \geq -B_i \forall i, t_2 \in T_{in}^{in}, t_1, s. \]  

(58)

With (56)–(58), the reserves are decomposed into the generator power blocks and are materialized as energy.

d) LSE1 reserves deployment and decomposition:

\[ LSE_{1,j_1,t_2,s}^{real} = LSE_{1,j_1,t_1,s}^{sch} - LSE_{1,j_1,t_2,s}^{up} + LSE_{1,j_1,t_2,s}^{dn} \forall j_1, t_2 \in T_{in}^{in}, t_1, s. \]  

(59)

\[ LSE_{1,j_1,t_2,s}^{up} = LSE_{1,j_1,t_2,s}^{up_{load}} + LSE_{1,j_1,t_2,s}^{up_{wind}} \forall j_1, t_2, s. \]  

(60)

\[ LSE_{1,j_1,t_2,s}^{dn} = LSE_{1,j_1,t_2,s}^{dn_{load}} + LSE_{1,j_1,t_2,s}^{dn_{wind}} \forall j_1, t_2, s. \]  

(61)

\[ 0 \leq LSE_{1,j_1,t_2,s}^{up} \leq LSE_{1,j_1,t_1,s}^{up} \forall j_1, t_2 \in T_{in}^{in}, t_1, s. \]  

(62)

\[ 0 \leq LSE_{1,j_1,t_2,s}^{dn} \leq LSE_{1,j_1,t_1,s}^{dn} \forall j_1, t_2 \in T_{in}^{in}, t_1, s. \]  

(63)

\[ \sum_{t_2} \frac{LSE_{1,j_1,t_2,s}^{real}}{\Delta T} = E_{req}^{j_1} \forall j_1, s. \]  

(64)

With (59), the actual consumption of the LSE1 is adjusted, while (60) and (61) decompose the deployed reserves by the LSE1. Similar to (62) and (63) that limit the deployed reserves by their scheduled value, up and down decomposed deployed reserves should also be constrained by their scheduled value. Equality (64) stands for the energy requirement constraint.

e) LSE2 reserves deployment and decomposition:

\[ LSE_{2,j_2,t_2,s}^{real} = LSE_{2,j_2,t_1,s}^{sch} - LSE_{2,j_2,t_2,s}^{up_{con}} + LSE_{2,j_2,t_2,s}^{dn_{con}} \forall j_2, t_2 \in T_{in}^{in}, t_1, s. \]  

(65)

\[ 0 \leq LSE_{2,j_2,t_2,s}^{up_{con}} \leq LSE_{2,j_2,t_2,s}^{up} \forall j_2, t_2 \in T_{in}^{in}, t_1, s. \]  

(66)

\[ 0 \leq LSE_{2,j_2,t_2,s}^{dn_{con}} \leq LSE_{2,j_2,t_2,s}^{dn} \forall j_2, t_2 \in T_{in}^{in}, t_1, s. \]  

(67)

Constraints (65)–(67) link the scheduled and the deployed contingency reserves procured by the LSE2. As stated before, no energy requirement constraints are enforced for this type of responsive load.

f) LSE2 reserves provision constraints:

\[ LSE_{2,j_2,t_2,s}^{up} = N_{2,j_2,t_2,s} - v_{LSE_{2,j_2,t_2,s}} \forall j_2, t_2, s. \]  

(68)

\[ LSE_{2,j_2,t_2,s}^{up_{con}} = N_{2,j_2,t_2,s} - v_{LSE_{2,j_2,t_2,s}} \forall j_2, t_2, s. \]  

(69)

\[ v_{LSE_{2,j_2,t_2,s}} \geq v_{LSE_{2,j_2,t_2,s}} \forall j_2, t_2, s. \]  

(70)

\[ v_{LSE_{2,j_2,t_2,s}} \geq v_{LSE_{2,j_2,t_2,s}} \forall j_2, t_2, s. \]  

(71)

\[ \sum_{t_2} v_{LSE_{2,j_2,t_2,s}} \leq N_{call_{j_2}} \forall j_2, t_2, s. \]  

(72)

\[ \tau = \frac{T_{in}^{in}}{j_2} + 1 \]  

(73)

Constraints (68)–(76) enforce several constraints related to the LSE2 deployment for reserve provision. Constraints (68)–(71) declare that, once called, a demand LSE2 type can provide only up or down contingency reserve, while (72)–(74) enforce the deployment logic of this type of resource. Equation (75) enforces the maximum number of times each LSE2 can be used to provide contingency reserves, while (76) constrains the maximum duration of each call to be at most $T_{in}^{in}$ periods.

The parameters that appear in these constraints are considered known and subject to a specific contract in which the demand responsible entity has agreed with the system operator. To consider more specific constraints, the technical and economic characteristics of the demand side should be known, although the way of implementing them is considered straightforward.
g) Load-following reserves determination:
\[
\sum_r \left( \begin{array}{l}
WP_{w,t_2,s} - S_{w,t_2,s} - W_{sch}^{w,t_1,s} \\
+ \sum_i \left( r_{dn,wind}^i - r_{up,wind}^i - r_{ns,wind}^i \right) \\
+ \sum_j \left( LSE_{j_1,t_2,s} - LSE_{j_1,t_2,s} \right)
\end{array} \right) \]
\forall i, j, t_1, t_2 \in T_{in}^2, t_1, s \tag{77}
\]
\[
\sum_r \left( \begin{array}{l}
D_{r,t_2,s}^2 - L_{shed}^r - D_{sch}^r \\
+ \sum_i \left( r_{up,load}^i + r_{ns,load}^i - r_{dn,load}^i \right) \\
+ \sum_j \left( LSE_{j_1,t_2,s}^u - LSE_{j_1,t_2,s}^d \right)
\end{array} \right) \]
\forall i, j, t_1, t_2 \in T_{in}^2, t_1, s. \tag{78}

Constraints (77) and (78) enforce the correct deployment of load-following reserves. Specifically, (77) enforces that if the net accepted wind during the actual operation of the power system is greater than the scheduled during the day-ahead clearing procedure, down reserves should be deployed: decrease in power output of the generating units or/and increase in the LSE of type 1 consumption. The contrary holds when the wind deviation is negative. According to (78), when the load deviation is positive, the units should increase their production or the LSE of type 1 should decrease consumption. The contrary holds if there is a negative load deviation.

III. Tests and Results

A. Illustrative Example

To demonstrate the proposed methodology, the sample system with four generators shown in Fig. 2 is analyzed over a 6-h horizon. It should be noted that all data are conceptual, based on typical values that can be found in the literature [44], in order to serve the illustrative purposes of this section. The technical and economic data for the generators are presented in Tables I and II, respectively. The network topology and the line data were derived from [45]. Without loss of generality, it is assumed that the economic data are constant through the scheduling horizon. Furthermore, all three generators are able to provide up- and down-spinning reserves, but only Units 3 and 4 can provide nonspinning reserve. At the beginning of the scheduling horizon, Units 1 and 2 are already synchronized for 5 h (300 min), providing 300 and 450 MW, respectively. Units 3 and 4 are down for 5 h (300 min). Besides, Unit 1 is considered a must-run unit. The initial conditions are treated within the context of the extension of the scheduling horizon as described in [44], applied here in both time-scales.

Economic and other data concerning the demand side, as well as the wind farm that has installed capacity of 100 MW, are given in Table III. Wind uncertainty is considered through three scenarios (high, moderate, and low), as shown in Table IV. The probabilities of occurrence for each scenario are 0.6 for high (S1), 0.2 for moderate (S2), and 0.2 for low (S3).

The inelastic load in the second stage is presented in Table VI, while the inelastic load considered in the first stage is presented in Table V. It is to be noted that the inelastic load in the second stage can differ up to 10% from the load of the first stage. The inelastic load is considered known in both stages and the relevant data are presented in Tables IV and V. The scheduled LSE1 load can vary up to 20% from the values in parentheses of Table V and can also provide up and down load following reserves within the same limits, while LSE2 follows...
the pattern of the same table, unless it is called to provide contingency reserves, altering its consumption by up to 50% up and down.

It should be noted that the requirement of fixed energy consumption within the scheduling horizon (load pickup) is enforced for the LSE1.

In this study, we consider that the must-run Unit 1 (which is also the unit with the largest capacity) fails at 14:10. Owing to the small size of the test system, transmission line failures would cause major disturbance to power flows and are not studied.

The results for the scheduled production, consumption, and reserves are presented in Tables V and VI. It is clear that the total energy required (expressed by the values in parentheses in Table V) by LSE1 is supplied during the scheduling horizon. Also, it can be seen from Table VI that the contingency is supported by the fast (and expensive) Units 3 and 4 (through nonspinning reserves), as well as from the demand side. The LSE2 responds 50 min after the contingency occurs and the contingency reserves from the LSE2 are used for 60 min (two calls). The response is not immediate because in period 5, the wind scenarios are higher than in period 4, and thus, reserves should also be procured to balance wind production. Thus, LSE2 response is used to relieve the system stress.

The results for different wind-scenario outcomes are given in Table VII. To clarify the model operation, we concentrate on the analysis of period 4, during which Unit 1 outage occurs. The scheduled production is 500 MW from Unit 1 and 384 MW from Unit 2. The production scheduled from the wind farm is 20 MW. The LSE1 is scheduled to be provided with 64 MW (with nominal consumption 80 MW) for this hour. LSE2 consumes 80 MW and the inelastic load is 760 MW. During this period, the inelastic load has a maximum increase at 4:00 (by 40 MW) and the maximum decrease

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<td>3:10</td>
<td>Nc</td>
<td>381 355)</td>
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<table>
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<th>Time</th>
<th>LSE1</th>
<th>LSE2</th>
<th>Inelastic</th>
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<tbody>
<tr>
<td>4:00</td>
<td>U1</td>
<td></td>
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<tr>
<td>4:10</td>
<td>Uw</td>
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<td>4:20</td>
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</table>

| Total upward | 32 | 44 | 80 | 569 | 517 | 365 |
| Total downward | 154 | 137 | 128 | 90 | 85 | 102 |

U, up; D, down; N, nonspinning; L, load; W, wind; C, contingency. Values are in MW.
occurs at 4:40 (by 32 MW). To balance this intra-hour load variation, load-following reserves are procured. Specifically, the load decrease is fully covered by Unit 2 (32 MW down-spinning load-following reserve). The intra-hour load increase is covered by Unit 3 that offers nonspinning reserves.

The maximum wind increase that is possible during this period occurs at 14:10 and 14:40, corresponding to 58 MW. To cover this fluctuation, 26 MW of up-spinning reserve are procured by Unit 2. Furthermore, LSE1 increases its consumption by 32 MW, offering down reserve. It is to be noted that in order to cover the wind fluctuations in other scenarios and intra-hour intervals during periods 4, 19, and 10 MW of nonspinning reserve are scheduled by Units 3 and 4, respectively. On the other hand, since the scheduled wind production from the wind farm is 20 MW (i.e., equal to the lowest value during this period) no reserves are needed to cover this deviation. It should be noted that no-wind production is spilled in any scenario.

As stated before, the contingency occurs at 14:10. Unit 1 is scheduled to provide 500 MW (technical maximum) during that hour. When the contingency occurs, this amount of energy has to be replaced by the other system resources. Fast Units 3 and 4 respond with 381 and 119 MW scheduled nonspinning reserve.

<table>
<thead>
<tr>
<th>Time</th>
<th>U1</th>
<th>U2</th>
<th>U3</th>
<th>U4</th>
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As a further test case (case 2), we consider that the total load of the system is inelastic; thus, the needed reserves have to be procured only from the generation side.

In Table VIII, the costs of procuring reserves from the generation side as well as the cost of energy are presented, comparing the previously presented case (with responsive demand—case 1) with the case in which reserve services can be procured only by generation side.

A decrease in the cost of producing energy and committing reserves from the generation-side is evident in case 1. The reduction in energy costs is caused because of the different UC schedule, and especially due to the expensive Unit 4 that in case 2 is scheduled to provide a large amount of energy (126 MW) in period 14. In case 1, this unit is not scheduled to provide energy. The reduction in the reserve commitment cost is related
mainly to the load-following reserve, which in case 1 is handled by the LSE1. From Tables III and VI, it can be concluded that the total cost to be paid for demand-side reserves is 1060 €. Thus, the net economic impact of the responsive demand is a cost reduction in 1208.96 €.

Finally, the impact of having different responsive demand capacities is examined. First, it is considered that LSE2 does not provide contingency reserves, and LSE1 up and down consumption alteration limits are spanning from 0% to 50%, in order to assess the performance of load-following reserves procurement from the demand side.

The results are presented in Table IX. It can be seen that procuring reserves from responsive demand is economically beneficial for the system in any case. Although the LSE1 consumption contributes increase in the social benefit (through the LSE1 utility), the system operator schedules as much down reserve from the LSE1 as possible. That is the reason why the total cost increases or decreases when the flexibility of the LSE1 increases.

The impact of providing contingency reserves from demand-side resources is then investigated, considering that LSE1 is not available to provide load-following reserves. LSE2 capability of altering its consumption is increased from 0% to 50%.

The relevant results are presented in Table X. In contrast with the previous tests, it is clear that contingency reserves procurement from the demand side reduces both energy and generation-side reserves cost, since it is not linked with any utility because it is paid when it is called to provide contingency reserves.

### B. 24-Node System

To investigate the scalability and generalize the conclusions drawn from the proposed methodology, it is also applied to a larger-scale test system and several studies are performed to evaluate the impact of introducing demand-side reserves.

The 24-node system that is analyzed here is based on the single area version of the IEEE Reliability Test System-1996 [46] and all the data are derived from [6]. It should be noted that the ramp rates of the generators were doubled, because the original Test System is designed for hourly intervals and thus it is difficult to achieve feasible solutions for the intra-hour time steps. Given the size of the problem, the intra-hour time step is 15 min.

All the tests that are presented in this section were performed for a horizon of 12 h. In order to reduce the size of the problem, generators have been grouped by type and bus, so that only one set of binary variables is used to determine the commitment status of one group of units. Grouping generating units by type and node is a technique that is commonly used in the relevant literature (e.g., [6] and [18]). Its aim is to reduce the number of binary variables related to UC. The idea behind this simplification is that units of the same technology (e.g., hydro, nuclear, etc.) that are connected at the same node are controlled using the same binary variables. The maximum power output is the sum of each single unit’s maximum power output and the minimum power output is the sum of each single unit’s minimum power output. The reduction in the computational burden depends on the number of units and their location and not on the number of nodes.

Hydro and nuclear units are considered must-run units. Also, only units at nodes 7, 13, 15, and 16 are considered technically capable of providing nonspinning reserves. Nonspinning reserves are assumed to be scheduled at a cost equal to 20% of the generator’s highest bid. Besides, all the units offer up- and down-spinning reserves at a cost equal to 25% of their highest bid.

Furthermore, the wind farm is assumed to be located at node 10 with an installed capacity of 200 MW. In order to force the system operator to integrate as much available energy, a very high value for the wind spillage cost is adopted, equal to 3000 €/MWh.

To adequately describe wind uncertainty, a sufficient number of scenarios have to be generated. Publicly available data [47] have been used in order to generate 10 hourly scenarios with a scenario generation technique based on the roulette wheel mechanism (RWM) [48].

The intra-hour deviations for the wind production have a mean average value equal to the hourly value of the wind power production scenarios and can deviate up to 3% for the intra-hour intervals. The scenarios normalized with respect to the capacity of the wind farm are presented in Fig. 3 and are equiprobable.

To enforce the security of the power system, the system operator does not allow involuntary load shedding.

For the sake of simplicity, no intra-hour load variations are considered. The LSE1 that are committed to provide load-following reserves offers this service at a value of 5 €/MWh. Furthermore, the utility of the LSE of type 1 is considered to be constant and omitted from the objective, so that the actual total expected cost is evaluated. The data for the LSE2 are the same such as in the six-node system case, with the only difference that the cost of scheduling contingency reserves from

<table>
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<th>TABLE IX</th>
<th>ENERGY AND RESERVES COSTS FOR DIFFERENT LSE1 FLEXIBILITIES</th>
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<td>Flexibility LSE1 (%)</td>
<td>Energy cost (€)</td>
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<tr>
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<table>
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<th>TABLE X</th>
<th>ENERGY AND RESERVES COSTS FOR DIFFERENT LSE2 FLEXIBILITIES</th>
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<td>40 646.425</td>
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<td>50</td>
<td>40 518.425</td>
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This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.
LSE2 is 0.25 €/MWh. The relatively low prices assumed for the reserves procured by LSE1 are based on the fact that in case of LSE1, the energy is not lost when it provides load-following reserves, but is recovered in other periods. Also, the LSE2 provides very low cost contingency reserves due to the fact that it is separately paid when it is called and such calls are infrequent.

In the first set of tests (Set 1), it is considered that no contingency occurs. The impact of load-following reserves procurement from the demand side is evaluated considering that the demand located at bus 20 (4.5% of the system load) can provide load-following reserves with flexibility that is spanning from 10% to 50%. Then the same tests are performed for the demand located at bus 18 (11.7% of the system load). Finally, it is assumed that loads located at buses 20 and 18 have both the ability to provide load-following reserves. The relevant results are presented in Table XI.

The expected spilled wind energy is calculated as the sum of the spilled available wind power production over the horizon, divided by the number of the intra-hour intervals and multiplied by the probability of the occurrence of the scenarios (since they are equiprobable).

It is clear from the results of Table XI that the incorporation of load-following demand-side reserves facilitates the integration of wind energy into the power system.

It can be noticed that as the ability of the elastic loads to deviate from their nominal power increases, the cost of the energy that is produced by the generators decreases and it is at the minimum when the loads at buses 18 and 20 are providing load following reserves with 30% flexibility.

The wind power that is spilled (and that is also penalized) follows the same trend, in general. It is to be stated that in most of the simulations of this test set, nonspinning reserve was scheduled from units located at bus 15 (30 MW) during period 11. In the same period, the greatest increase in the consumption of the LSE of type 1 loads is noticed.

In the second set of tests (Set 2), it is considered that the outage of the must-run nuclear unit located at bus 18 (400 MW) occurs at period 7:30. Then, during period 9:30, the transmission line 33 with capacity 1000 MW fails. These two contingencies have a serious impact on system operation. First, it is assumed that no contingency-reserves can be procured by the demand side.

The performance of the demand-side contingency reserves is evaluated by consecutively considering loads at buses 3 (6.3% of the system load) and 18 (11.7% of the system load) being able to alter their consumption by 50%. Finally, both loads of these buses are considered LSE of type 2 with the same flexibility.

The results are presented in Table XII. The scheduled energy cost is not affected after the integration of the LSE of type 2, since this type of responsive demand is scheduled to consume its nominal power, unlike the LSE of type 1 that generally contributes in the energy cost reduction through its energy provision need reallocation.

The demand that is located at bus 3 is called two consecutive times and offers 80 MW up contingency reserve during period 10 that corresponds to the highest system loading condition. This leads to less reserve scheduled during that hour that would be provided by units that operate at a high marginal cost power block. Next, the demand that is located at bus 18 is called one time as soon as the contingency occurs to provide 115 MW of contingency reserve. Also, it is called during period 11 that corresponds also to a high total system load in order to reduce the generation-side reserve cost. Furthermore, when both loads at buses 3 and 18 are available for contingency reserve procurement, the demand at bus 18 offers 115 MW in period 7 and 149 MW of up reserve in period 11.

Similarly, the demand at bus 3 offers 62 MW during period 7 and 80 MW during period 11. This leads to a reduced need of generation-side reserves as soon as the contingency occurs and when the system load is at its peak.
that as the demand-side contingency reserve capacity increases, the generation-side contingency reserve cost is reduced.

As a final study (Set 3), it is considered that loads at buses 18 and 3 are available for contingency reserve procurement and the load of bus 20 can provide load-following reserves with 30% flexibility. This case is compared with the case in which the load of bus 20 is inflexible, already presented.

The relevant results are presented in Table XIII. The energy cost reduction in the first case is a result of the increased wind power integration and of the reallocation of the energy provision of the LSE of type 1 located at bus 20. The scheduled reserve costs are higher because 979.5 € are spent on load-following reserve, while nonspinning reserves are scheduled from Unit 5 in period 11. Besides, this increase in the reserve costs allows a greater portion of the wind power generation to be integrated into the system.

### C. Computational Statistics

The proposed model is solved using MILP techniques in GAMS 24.0.2 software package [49] by CPLEX 12 solver. The computer used for the simulations is a workstation with two 3.47 GHz six-core processors and 96 GB of RAM, running 64 bit windows operating system. The relevant results are presented in Table XIV. It should be noted that for each test set, the statistics for the computationally worst case have been presented. Also, the relative duality gap is set to 0% for all test cases, except for the case presented for Set 2 for which it set to $10^{-4}$. It is obvious that the size of the problem by means of the number of equations and variables is not necessarily a determinant factor for the computational burden linked to a MILP problem. For instance, the six-node system requires more computational effort than several tests performed on the 24-node system, mainly because the network constraints are binding in the first case.

### IV. Conclusion

In this study, a two-stage stochastic programming model has been developed in order to specify the optimal response of a system facing different sources of uncertainty, namely intra-hour load and wind generation deviations, transmission line, and generating units outages. As seen from the illustrative test case, although using different time-scales may increase the modeling complexity, the computational burden, and the amount of output data, it provides a better insight into the actual operation of a power system. It should be stated that through the proposed methodology, it becomes clear that the integration in large-scale of volatile power resources, such as wind, directly affects the reliability of a power system. System operators should consider developing new AS that would be more specific, targeted to balance the negative effects of the uncertainty and variability introduced by different factors. Extensive simulations presented in this paper allowed concluding that by exploiting the advantages that the demand side can offer, the system gains a flexible asset to cope with normal operations as well as with emergency events in an economic way.

The applicability of the presented methodology depends on the computational time required to solve the optimization problem. Measures that can be applied to reduce the computational burden include the following.

1. Proceed in the solution of the problem with a relative duality gap greater than 0%. This will affect the quality of the solution, and thus, this measure should be carefully applied, after an acceptable trade-off between solution time and quality has been determined.
2. Utilize modern computing techniques such as grid and cloud computing. Since there are already companies that provide computational power at affordable prices, this proposal promises tractability even for large-scale mathematical programming problems. Also, commercially available software has evolved to support such techniques, recently.
3. The technological advances are of unquestionable importance, though special attention should be given in the efficient modeling of a problem. Decomposition techniques, such as Bender’s decomposition, allow exploiting efficiently the developments in the informatics field.

The proposed approach can be extended to consider load deviations and contingencies through scenarios. The concept of utilizing different time-scales for every stage of the model allows the development of multistage stochastic programming models. Such models could be useful in examining the interaction between different market structures in several time-scales as well as assessing the value of the incomplete information.
about random variables (e.g., wind forecasts and load forecasts) available at every decision making point. The above topics will be considered in future studies of the authors.

REFERENCES


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