A Predictive Control Scheme for Automated Demand Response Mechanisms

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***Abstract*--The development of demand response mechanisms can provide a considerable option for the integration of renewable energy sources and the establishment of efficient generation and delivery of electrical power. The full potential of demand response can be significant, but its exploration still remains a challenge mainly due to the non-homogeneity and the distributed nature of energy resources. Recent advances in information and communication technologies create new opportunities for close to real-time adaptation of the demand for electricity to the actual system needs. However, there have been many different approaches in transforming this vision into practical applications. Herewith, a novel control scheme for automated demand response mechanisms is proposed based on the application of predictive control techniques. The proposed scheme supports the large-scale implementation of demand response programs, and captures the planning phase, the real-time operations, the verification of the energy and service provision, and the financial settlement.**

***Index Terms*--Power system planning, power system control, supply and demand, demand forecasting, predictive control.**

NOMENCLATURE

The list below includes the main notation of this paper and is intended for quick reference, while other symbols are defined throughout the text.

i	Discrete step for future control periods, $i=1,\ldots, n$
i_p	Discrete step for past control periods, $i_p=1,\ldots, n$
k	Current discrete time control period
k_d	Beginning of first control period of day d
l	Discrete step for the settlement periods, $l=1,\ldots, m$
$p(l)$	Schedule for the day ahead (W)
$q(l)$	Aggregate bids for operating reserves (W)
$r_j(k+i\|k)$	Reference trajectory of the j-th process (W)
$r(k+i\|k)$	Aggregate reference trajectory (W)
$s(k+i\|k)$	Processed set-point trajectory (W)
$u_j(k+i\|k)$	Input trajectory of the j-th process
$w_j(k+i\|k)$	Adjusted notification trajectory (W)
$w_j(k)$	Binary notification signal
$y_j(k)$	Power output of the j-th process (W)
$y(k)$	Aggregate power output (W)
τ, τ_{rec}, $\tau_{horizon}$, τ_{ref}, τ_s	Time intervals (sec.)

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I. INTRODUCTION

THE electricity grid provides a vital and integral service to our modern society. However, the current grid architecture did not emerge at an instant. The power system evolution is a continuous process, influenced by an immense number of factors. Currently, encouraged by a general trend towards deregulation, wholesale markets for electricity have been established in many countries, and those are often complemented by markets for ancillary services. Inherently, the liberalisation of the electricity sector entails a transition to decentralised operations. At the same time, the increasing integration of intermittent renewable energy sources (RES), due to environmental concerns, further complicates the power system management. Taking into account these developments, it becomes apparent that the power system design and control structure have to be adapted to cope with future challenges.

Demand response (DR) mechanisms can play an important role in future energy management systems, but their full exploration still remains a challenge. Predominantly, DR mechanisms have been applied in a limited number of large industrial processes, while previous research has been mainly focused on the management of groups of homogeneous distributed resources (e.g. identical electrical space heaters in [1]), or on specific applications (e.g. frequency-based control in [2]). The purpose of this paper is to provide a viable architecture for automated DR based on the application of predictive control. The elucidated ideas reflect a broad scope of services, provided by DR mechanisms, with respect to the requirements for power system control in liberalised market environments. The proposed control scheme considers a uniform representation of non-homogeneous distributed energy resources and allows the participation of virtually all system users, irrespectively of their size, in electricity markets. Furthermore, a uniform control signal is specified that allows the deployment of fast operating reserves, in line with the requirements for power system stability and reliability. The application of model-based predictive control (MPC) has been studied for the active load management in a power system which is characterised by high penetration of RES and proved to be an appropriate tool for supporting different technologies and goals [1]. In addition, predictive control schemes are compatible with the notion of deregulated power systems since the system planning (*a priori*) and real-time operations, as well as the market-based settlement (*a posteriori*) are interrelated with the predictions over a receding horizon [3].

II. System Design

An electrical power system consists of different control areas interconnected through high voltage (HV) synchronous or asynchronous connections. In Europe, the HV transmission system of a certain control area is operated by the transmission system operator (TSO), the legal entity that monitors the electricity network, ensures the connections with foreign control areas, and organises the markets for operating reserves and cross-border capacity. Regional distribution system operators (DSO) connect individual customers to the grid and provide the distribution of electricity. In liberalised market environments, these companies are legally and organisationally independent from the traditional suppliers. Medium voltage (MV) electrical networks are connected to low voltage (LV) networks through MV/LV transformer substations, which subsequently feed a large number of end-users at the LV level.

A. Demand Response Mechanisms

Electricity end-use can become responsive to a wide range of control signals such as price, resources availability, and network reliability, and play an important role in future energy management systems. However, the utilisation of an aggregation of non-homogeneous distributed resources during power system planning and real-time operations requires a uniform representation of those. For example, at system level, the TSO needs to know what operating reserves are available, but does not need to be informed with all the details of each distributed resource. Therefore, each distributed energy resource (DER) is distinguished from another, not based on its physical specifications and operational functions, but in terms of energy capabilities (i.e. the characteristics of energy utilisation). These energy capabilities can be attributed to different markets and services, e.g. ancillary services, and subsequently DER can be aggregated to form groups which deliver these services.

The aggregator can hold contracts with system users connected to various voltage levels, and represent them up to the system and market operators. This concept of aggregation is relevant to the operation of virtual power plants (VPP), where large numbers of geographically dispersed devices are coordinated and operated as a single entity, and in parallel to the existing power system.

In this work, the terminology of OpenADR [4] is adopted, where the following entities are distinguished: the virtual top node (VTN), and the virtual end node (VEN). A system entity can be a VTN, VEN, or a combination of those. Furthermore, a VTN has one or more associated VEN, while a VEN is a device or system that can exchange communication signals, and can also control electricity end-use and generation. For the purpose of this work, three main actors are distinguished: the *system operators* (including the transmission system operator, distribution system operators and electricity market operators), the *aggregators* (envisioned legal entities that hold contracts with system users and coordinate them in real-time), and the *system users* (e.g. generators and consumers).

Herewith, a decentralised control structure with a global coordinator (i.e. the aggregator) is proposed. One might envision a hierarchical node architecture for DR, as the one illustrated in Fig. 1, where the system operators are represented by a VTN that communicates with the aggregator. The latter can be seen as a VEN with respect to the system operators, but at the same time the aggregator can be considered as a VTN associated with a number of VEN (e.g. generators and/or loads). The VTN/VEN concept provides a standardised way to represent any distributed resource or groups of resources to the system level, while a VEN can control a resource or a group of resources [4]. As can be seen in Fig. 1, the aggregator is linked with a household connected to the LV level which can be considered as a home area network (HAN) interconnecting a number of controllable loads (e.g. washing machine, battery charger for an electric vehicle etc.). Thus, in the latter case this household can subsequently be seen as a VTN with a number of associated VEN. The recursive nature of this architecture provides a scalable and generic framework for the management of non-homogeneous distributed resources in a uniform manner. In this work, the focus is on the interactions between one VTN (i.e. the aggregator) and a number of associated system users (i.e. the VEN_j, where $j=1,..., N$). The aggregator can be seen as the operator of a VPP which consists of an aggregation of distributed resources, e.g. loads and generators.

Furthermore, since an aggregator is aggregating resources which are geographically dispersed, it is also important to account for the spatial dimension. In the case that congestion relief or voltage control in distribution grids are some of the ancillary services that DR mechanisms might offer to grid operators, then resources should be aggregated in clusters which represent a limited geographical area. Thus, every VEN*j* which resides downstream the aggregator (i.e. the VTN), collects information and forwards this to the upper level accompanied with a tag that captures the spatial dimension (e.g. postcode, substation, feeder, phase etc.).

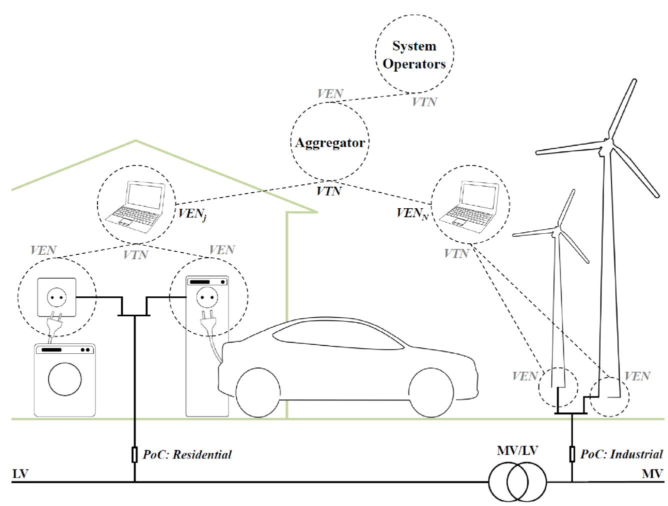

Fig. 1. Schematic of the demand response architecture. The aggregator can be seen as the operator of a virtual power plant which consists of residential customers and wind-energy installations. The black lines depict the physical power system and the points of connections (PoC) with system users, while the dashed lines represent the communication links between system entities.

B. Information Specification

A starting point for synthesis of a control scheme is to specify the required information which is on the disposal of the controller, as well as the information that the controller is required to communicate to other entities in the system. However, the specification of this information is depending on the relevant application, since each application and business model imposes different requirements and constraints. In this work, the descriptions of the optimisation problems are built upon an analysis of electricity markets and power system operations. In wholesale electricity markets, the commodity is energy traded over a specific time period, the so-called settlement period. However, for ensuring the system security (i.e. the real-time markets), it is essential to continuously maintain the power balance through the activation of different types of operating reserves. For example, in the Netherlands, in the case that frequency deviations and/or deviations of inter-area exchanges occur, bids for operating reserves are called and the TSO sends an automatic control signal (which is updated every 4 sec.) to the associated service providers [3]. This frequently updated automatic control signal is actually a real power set-point trajectory. For the purpose of this work a processed set-point trajectory $s(k+i|k)$ is defined which is constructed by the aggregator (i.e. the VTN) and is broadcasted to the associated system users (e.g. each VEN_j), at time instant k. Then, each system user can decide internally and in a decentralised manner how to respond to this signal.

An example of the processed set-point trajectory $s(k+i|k)$ is illustrated in Fig. 2 (a), considering that is sent at current time instant $k=0,$ and is discretised in i steps, where $1\leq i\leq n$, to address the control horizon. The time interval for simulations and for sampling analogue measurements is denoted as τ, and satisfies the following condition: $max(i)\cdot\tau=n\cdot\tau=24$ hours. For example, if a control period has a duration of $\tau=4$ (sec.), then a horizon of 24 hours corresponds to $n=21\ 600$ discrete time control periods. In a discrete time control procedure, the variable parameters are assumed constant during each control period, and their instantaneous values are defined at the beginning of the control period k (equivalently, at the end of the control period $k-1$). The notation $s(k+i|k)$ indicates that the reference trajectory depends on the conditions at time instant k [5]. The processed set-point trajectory $s(k+i|k)$ actually represents the short-term objectives for DR, and is constructed based on information about: a) real-time requests from system operators for the provision of ancillary services, e.g. load frequency control (LFC) signals, b) short-term predictions about the system state, and c) past control errors. In Fig. 2 (a), positive power values (denoted as *active period*) are followed by negative values (denoted as *recovery period*). The reason behind this choice is to illustrate the possibility for how load-shifting actions can be incorporated in the control signal. Specifically, a load process can be curtailed (e.g. energy not served) or can be shifted in time (e.g. postponed). In the latter case, if a load cycle is postponed, then the load profile is characterised by a load reduction at the point where the load cycle would occur in the absence of control, and this load reduction is followed by a load increase at the point where the load cycle eventually occurs in response to the control signal. In power system control, an action of load reduction or increase is equivalent to up-regulation or down-regulation respectively. As can be seen in Fig. 2 (a), between the *active period* and the *recovery period*, there is a time interval denoted as τ_{rec}. By setting an appropriate value for τ_{rec} the aggregator can define a minimum time period after which the loads can recover their operation, e.g. following a load-shifting action. Ultimately, the control signals must be in some form of power set-points and energy figures, accompanied with prices when necessary to address market-based operations and an example is illustrated in Fig. 2 (b). Note that in this figure, negative prices refer to a payment from the system users to the aggregator and vice-versa.

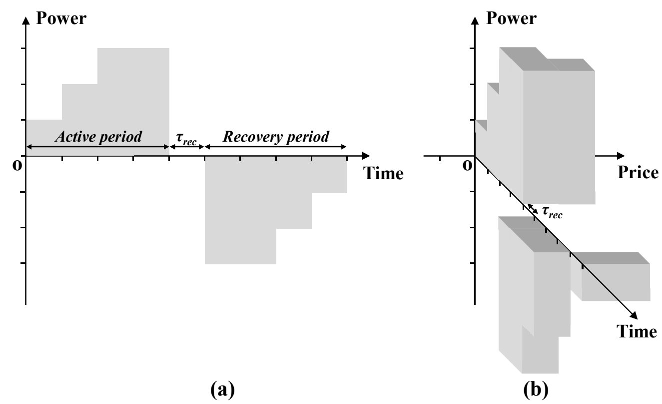

Fig. 2. (a) Example of the processed set-point trajectory $s(k+i|k)$ which is sent at time instant $k=0$. (b) Three dimensional plot of the processed set-point trajectory $s(k+i|k)$ accompanied with prices. In both figures time is discretised in i steps, while the x-axis represents the control horizon.

III. Model-Based Predictive Control

MPC refers to a class of control algorithms that utilise an internal model to predict the future response of a process. At each control interval an MPC algorithm optimises future process behaviour by computing a sequence of future inputs. The first value in the optimal sequence of inputs is applied to the process and the entire calculation is repeated at subsequent control intervals.

The sequence of actions is distinguished between planning (*a priori*), operations (*real-time*) and financial settlement (*a posteriori*). The details of each phase and the interactions between system entities are further discussed in the following paragraphs. Emphasis is given on the operations of the day-ahead wholesale market and the real-time market for operating reserves. Short-term system optimisation is mainly applied during the day-ahead and proceeds in parallel with the real-time operations on the actual operational day. The gate closure time (GCT) of the day-ahead market occurs at midday, while the verification of the service provision and the financial settlement occur after the operational day.

A. Planning and Scheduling

During the planning phase, all system users must inform their associated aggregator about their energy schedules for the day-ahead. These energy schedules are actually predicted positions for the day-ahead in kWh and for each settlement period, and must be forwarded to the aggregator prior to the GCT of the day-ahead market (e.g. two hours prior to GCT). The aggregator collects all information and creates aggregate order books, which are submitted to the operator of the day-ahead market before the GCT (e.g. one hour in prior). The aggregator can influence system users during planning, e.g. by publishing a day-ahead set-point trajectory or day-ahead price predictions. However, for simplicity reasons, this aspect is omitted from the following descriptions where it is assumed that each system user calculates its predicted positions independently.

At midday is the GCT of the day-ahead auction and immediately after the closing, individual matching results are becoming available. Within one hour after the GCT the aggregator has been informed about the day-ahead market clearing volumes and prices, and submits to the TSO the complete energy schedule $p(l)$ for the day ahead. Then, the TSO performs consistency checks and verifies the submitted schedule. The energy schedule $p(l)$ is actually a piecewise constant function, with a fixed power value for each settlement period τ_s, where l is a positive integer that satisfies the following condition: $max(l)\cdot\tau_s=m\cdot\tau_s=24$ (hours). For example, considering that each settlement period corresponds to a time period of 15 min., $\tau_s=900$ (sec.)$=15$ (min.), then $m=96$ to address a planning horizon of 24 hours. Note that the settlement period τ_s can take values ranging from a few minutes to one hour, e.g. 15, 30, or 60 min., depending on the market design in the considered control area.

The energy schedule $p(l)$ is based on long-term (forward and future markets) and short-term trade (spot markets). This energy schedule is actually constructed based on individual predictions $r_j(k_d+i-1|k_d-i_p)$ that are sent from the system users to the aggregator a number of control periods i_p prior to k_d, where k_d corresponds to the time instant that indicates the beginning of the first control period of the operational day d (e.g. at midnight, T00:00:00). For example, considering the time interval for simulations τ, then the product $i_p\cdot\tau$ can be set to reflect a period of approximately 14 hours before midnight, while in this case the prediction horizon k_d+i-1, where $i=1,\ldots, n$, should address a period of 24 hours.

Following the clearing of the day-ahead auction, the system users submit to the aggregator their energy capabilities for ancillary services (e.g. provision of operating reserves). These energy capabilities are calculated in steady-state, i.e. for each settlement period separately, and are submitted in terms of price in €/MWh and/or volume in MWh per settlement period. The aggregator collects and processes all information from associated system users, creates aggregate bids for secondary reserves and eventually submits bids to the operator of the real-time balancing market. These bids are in the form of a piecewise constant function $q(l)$ with a finite value for each settlement period τ_s of the day-ahead. Note that the settlement period for the day-ahead auction and the real-time balancing market are distinct. However, in this work, the same duration is assumed (e.g. 15 min.) and is denoted by the same symbol τ_s. In Section VI (Appendix A), a simulation pseudo code for the planning phase is provided.

B. Real-Time Operations

The proposed control scheme is based on feedback control at the aggregator (i.e. the VTN) and distributed feedforward MPC at each associated system user (i.e. each VENj). The real-time operations of the control scheme are illustrated in Fig. 3, where it is assumed for illustration reasons that each VENj represents only one process. The model predictive controller at the j-th VEN has an internal model which is used to predict and optimise the behaviour of the j-th process output $y_j(k)$ over a future prediction horizon starting at current time instant k. For example, the internal model can represent the charging process for an electric vehicle, and apart from the technical aspects of the process, it should also take into account the user behaviour, e.g. driving patterns and schedules [6]. Furthermore, the controller located at the VTN can also incorporate models for creating predictions about the future system state (e.g. predicted power imbalance) and weather forecasts.

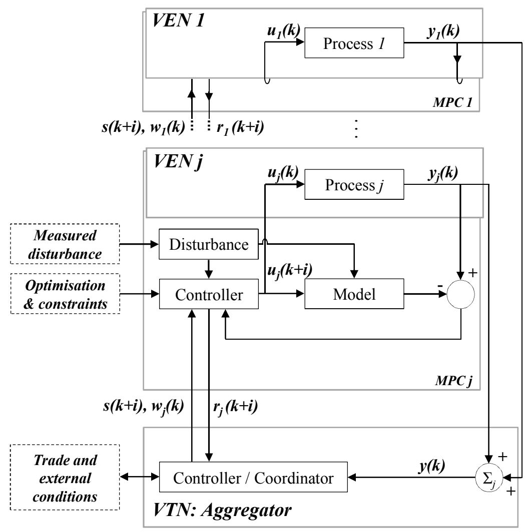

Fig. 3. Illustration of the real-time operations at time instant k. The VTN represents the aggregator that has a number of associated VEN, while the j-th VEN is illustrated together with the MPC block.

An illustrative example of the operations under the proposed control scheme is given in Fig. 4, while the illustrated signals are further explained below. Prior to real-time operations, the aggregator has determined a portfolio-based energy schedule $p(l)$ for the day ahead, which is actually a piecewise constant function, with m finite pieces, one for each settlement period τ_s of the day ahead. This energy schedule is based on the portfolio of the aggregator and on predicted customer profiles and weather conditions and it reflects the energy volumes settled on long-term and short-term markets. However, in practice, several imbalances occur in real-time and cause deviations from the original energy schedules. Sometimes these imbalances cancel out each other, but any remaining imbalance must be internally solved by the aggregator before the end of the settlement period, or settled with the TSO through the imbalance settlement [3]. During operations, the aggregator continuously receives aggregate information from individual system users and maintains knowledge about available resources originating from the end of the line. An example of the energy schedule $p(l)$ is illustrated in Fig. 4 (a), considering that $\tau_s=15$ (min.). In parallel with the energy schedule, the aggregator has defined *a priori* a power reference trajectory $r(k+i|k-i_p)$ that complies with the energy schedule and an example is illustrated in Fig. 4 (a). The notation $r(k+i|k-i_p)$ indicates that the reference trajectory depends on the conditions at time $k-i_p$, where i_p can be set to reflect the planning period e.g. between minutes and hours ahead of current time instant k. The reference trajectory $r(k+i|k-i_p)$ consists of the sum $\Sigma_j r_j(k+i|k-i_p)$, where $j=1,..., N$ corresponds to all associated system users (i.e. the VEN$_j$), and is defined prior to real-time operations (e.g. day ahead). The trajectory signal $r(k+i|k-i_p)$ is actually a projection of the aggregate output if no external control signal is received in real-time. Note that the time interval i_p can take different values for each VEN$_j$, which means that the signals $r_j(k+i|k-i_p)$ can be forwarded to the VTN in an asynchronous way, and not necessary at the same time instant. Since each system user runs processes with different dynamics, the computations at each VEN$_j$, and the subsequent communication with the VTN can occur asynchronously.

As discussed in Section II.B, in the proposed scheme, the aggregator defines the processed set-point trajectory $s(k+i|k)$ in real-time and then broadcasts this to all associated VEN*j* (under a certain control area) at time instant k. The processed set-point trajectory $s(k+i|k)$ accounts for real-time requests, e.g. LFC signals sent by the TSO, but also for compensation of past errors with respect to the energy schedule $p(l)$. An example of the processed set-point trajectory $s(k+i|k)$ is illustrated in Fig 4 (b), where starting at current time $t=60$ (min.) and until $t=160$ (min.), the aggregator requests upwards regulation (i.e. generation increase or load reduction). The time period from current time $t=60$ (min.) and until $t=160$ (min.) corresponds to the control periods from $k=900$ and until $k=2400,$ given that $\tau=4$ (sec.). However, for illustration reasons, in Fig. 4, the *x*-axis represents the time in minutes and not in discrete steps of control periods. Each individual VEN*j* obtains the processed set-point trajectory $s(k+i|k)$, and checks (based on predictions) whether it can partially contribute to the requested action. Then, VEN*j* sends back to the aggregator the reference signal $r_j(k+i|k)$ which includes the information about the part that can be fulfilled. An example of the signal $r_j(k+i|k)$ is depicted in Fig. 4 (c), illustrating the time-shifting of the charging process of an electric vehicle from $t=60$ (min.) to $t=170$ (min.). In this example, the charging process represents a controllable load process corresponding to single-phase charging with a maximum power of 3 (kW). This specific example is provided for illustration purposes and does not reflect the function of discharging the batteries to inject power back to the grid. However, the proposed control scheme provides a generic framework for the management of non-homogeneous distributed resources and in this context also Vehicle-to-Grid (V2G) functions can be incorporated.

Note that the reference signal $r_j(k+i|k)$ is frequently updated in real-time and it is distinct from the reference signal $r_j(k+i|k-i_p)$. The aggregator receives the reference signal $r_j(k+i|k)$ and performs consistency checks (e.g. overshooting avoidance). Then, it sends back to the VEN*j* a discrete binary notification signal $w_j(k)\in\{0,1\}$ to indicate rejection or acceptance with respect to $r_j(k+i|k)$. In case of acceptance, the VEN*j* performs the control actions, i.e. the next input $u_j(k)$ is applied in the process *j*. Note that the input signal can be either a set-point value or a switching *on/off* command. Then, the aggregator subtracts the fulfilled actions, based on the sum $r(k+i|k)=\Sigma_j r_j(k+i|k)$, recalculates and forwards the updated processed set-point trajectory $s(k+i+1|k+1)$ and the whole process is repeated. This control strategy is called the receding horizon strategy, since the prediction horizon remains of the same length [5]. Alternatively, instead of the binary notification signal $w_j(k)$ the aggregator has also the option to send back to the VEN*j* an adjusted reference trajectory signal $w_j(k+i|k)$ which indicates that the submitted reference signal $r_j(k+i|k)$ is partially accepted or should be shifted in time to get accepted. The sum of the total power use and generation at current time instant k is the VPP real-time output $y(k)=\Sigma_j y_j(k)$. To overcome the DR system error, the feedback loop is structured at the VTN level, where the VPP real-time output $y(k)$ and the predictive output $r_j(k+i|k)$ of each individual VEN*j* are utilised. The global objective is to control the future output $y(k+i)$ according to the sum of the set-point trajectory $r(k+i|k-i_p)$ (which is sent *a priori*) and the processed set-point trajectory $s(k+i|k)$ (which is sent in real-time). An example is illustrated in Fig. 4(d), where the VPP output $y(k)$ ideally follows the sum of these signals, up to the current time instant k. In Section VII (Appendix B) a simulation pseudo code for the real-time operations is provided.

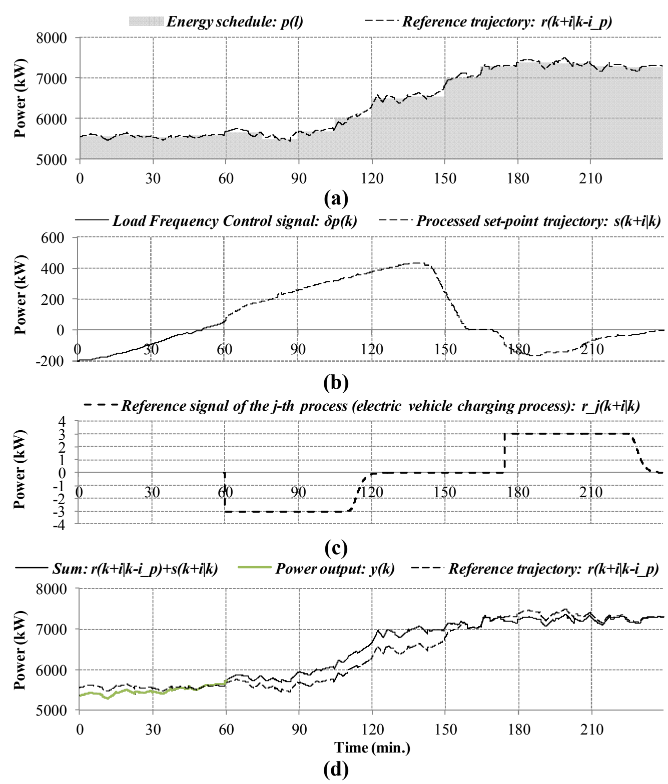

Fig. 4. Illustrative example of the communications signals between the system operator, the aggregator and an individual system user that is representing the charging process for an electric vehicle, considering that the current time is $t=60$ (min.).

C. Verification and Financial Settlement

The verification of the service provision by the TSO and the financial settlement by the market operators are performed *a posteriori*, i.e. after the operational day. As discussed in the previous section, any energy imbalance with respect to the energy schedule $p(l)$ must be internally solved by the aggregator before the end of the l-th settlement period, or settled with the TSO through the imbalance settlement [3]. This can be expressed through the following equation:

$$\int_{(l-1)\cdot\tau_s}^{l\cdot\tau_s} y(t)\cdot dt - p(l)\cdot\tau_s = z(l)\cdot\tau_s \qquad (1)$$

where $t \in [(l-1)\cdot\tau_s,\ l\cdot\tau_s]$, while the aggregator has to comply with the submitted energy schedule $p(l)$, $l=1,\ldots, m$, for each settlement period τ_s of the day ahead, but is free to decide the shape of the continuous power profile $y(t)$ within each settlement period τ_s. However, any mismatch from the submitted schedule will be regarded as an imbalance $z(l)$ for the l-th settlement period τ_s.

For the verification of the provision of operating reserves by the TSO, apart from the real-time measurements of the VPP output $y(k)$, a reference value $r(k)$ is required, which must be sent by the aggregator to the TSO just before realisation. This reference value indicates the planned output of the VPP, at a specific time instant in the short-term future, so that the TSO can check whether the aggregator actually delivered the real-time requests (e.g. for the provision of fast operating reserves). This reference signal is constructed within the VTN block (i.e. the aggregator) based on the incoming signals $r_j(k+i_{ref}|k)$ from each individual VENj:

$$r(k+i_{ref}|k)=\Sigma_j r_j(k+i_{ref}|k) \qquad (2)$$

where i_{ref} is a constant that determines a number of subsequent control periods. Considering the time interval τ for simulations, then the product $i_{ref}\cdot\tau=\tau_{ref}$ defines the time period between forwarding this reference value to the TSO and the actual realisation. The aggregator will try to keep this time period as short as possible to have the opportunity to act fast on changed situations. In the Netherlands, this time interval τ_{ref} has been set to one minute [3].

The financial settlement between the aggregator and associated system users is based on bilateral contractual agreements. The aggregator can organise and operate an internal single-sided market for system users, and the specific agreements can vary depending on the system users' preferences. For example, system users can participate in the aggregator's single-sided market under a pay-as-bid scheme or on a voluntary basis.

Especially for residential customers that have limited capacity and controllability over the processes that run within their premises, the aggregator can define tailored DR programs that incentivise participation and at the same time provide a protective pricing environment. These aspects are further discussed in the next paragraph.

D. Objective Functions and Constraints

MPC transforms a control problem into an optimisation problem, which can be solved over a prediction horizon, subject to system dynamics, an objective function, and constraints. An analysis of electricity markets and power system operations indicates that the involvement of different timescales and types of system users imposes different constraints and results in various problems that must be formulated and solved separately. In this section, the problems related to the utilisation of an aggregation of non-homogeneous distributed resources during electricity markets and power system operations are outlined. Emphasis is given in identifying the main objectives and constraints of the aggregator and associated system users.

The role of the aggregator (i.e. the VTN) is to represent system users to markets, and to communicate with system operators. For the VTN, the objective function can be a cost function that minimises costs, or a profit function that maximises profits for trading electricity in wholesale markets, and that maximises the revenues from the provision of ancillary services to the system. Thus, the aggregator submits schedules *a priori* for electricity wholesale trade and options for ancillary services, subject to the individual system users' requirements and capabilities. Then, during real-time operations, the VTN has to respect the submitted schedules and options. The VTN can influence the behaviour of individual system users (VENj) by defining in real-time the processed set-point trajectory $s(k+i|k)$ which is the set-point trajectory that accounts for deviations from the submitted energy schedules and for real-time requests from system operators (e.g. for the provision of operating reserves). Once the processed set-point trajectory $s(k+i|k)$, has been broadcasted, then it is up to each individual system user (i.e. the VENj) to react in an appropriate way so that the global objectives of the VTN are fulfilled. Since system users (e.g. industrial, commercial, residential customers) have different objectives then the individual formulations will result in various problems to be solved. The challenge for the VTN is to define the processed set-point trajectory $s(k+i|k)$ in a way that incentivises each individual VENj so that the future output $y_j(k+i|k)$ contributes to the global objectives of the VTN. In this context, convergence can be achieved, but without reaching an optimal solution, since there is no central optimisation. However, the aggregator can shape the aggregate response by setting margins for short-term actions and thus minimise inefficient operations.

For demand side management, the objective function of an individual system user (i.e. the VENj) is defined with respect to the demand response program specified in the bilateral contractual agreement with the aggregator (i.e. the VTN). Each system user has different needs and different options are required to address those diverse needs. Thus, customer segmentation and the definition of tailored DR programs are required. For example, under a price-based program such as time of use (ToU) tariffs or real-time pricing (RTP) with hourly resolution [7], the objective function can be formulated as a function that minimises the total costs for purchasing an amount of electrical energy for each hour h, with a horizon of e.g. 24 hours. Ideally end-users are still in control of their assets, and they can define their preferences and constraints (e.g. define maximum time for postponing a load cycle), but at the same time they provide flexibility to the system. Furthermore, the objective function of the j-th VEN can also take into account trade-offs. For example, a user might be willing to accept less comfort levels in response to more monetary benefits by defining a cost function, or can maintain specific comfort levels by defining restrictive constraints (e.g. for a space conditioning unit the objective function can be formulated to also minimise the difference between the indoor air temperature and a given reference temperature [1]). For fast DR actions, such as the provision of operating reserves for secondary control [3], system users (e.g. industrial and large commercial customers) can submit bids (i.e. offers accompanied with prices), in an internal single-sided market which is organised by the aggregator. Then the objective function can be formulated as a weight function that combines both objectives: the minimisation of the total costs for purchasing electricity, and the maximisation of the revenues for the provision of operating reserves and other ancillary services.

However, for residential customers or any other category of vulnerable customers that have limited capacity and controllability over the processes that run within their premises, a different approach is proposed. The aggregator can make agreements with residential customers that incentivise participation and at the same time provide a protective pricing environment for them. In this case the objective function can be formulated as a function that maximises the participation performance (e.g. maximises the service provision). For example, for the provision of operating reserves, the individual VENj can calculate the reference signal $r_j(k+i|k)$ in a way that the energy content $\int r_j(k+i|k)\cdot di$ offered to the aggregator over a time horizon, starting at current time instant k, is maximised. Another aspect that can be incorporated in the objective functions of the system users is to minimise the reaction time with respect to time instant k (e.g. minimise the control period i with respect to k that $r_j(k+i|k)\neq 0$, while $r_j(k+i|k)$ is partially contributing to the global objective). That would result in a fast response and the aggregator should reward this by creating appropriate incentives. In brief, the aggregator can define a participation function for assessing the performance of associated system users. Then, the economic benefits can be distributed among system users in relation to their participation performance.

IV. Discussion

In this paper, a proposal is presented for a viable architecture for automated demand response mechanisms, based on the application of predictive control. The proposed control scheme considers a uniform representation of non-homogeneous distributed energy resources and allows the participation of virtually all system users in electricity markets. In the descriptions, emphasis is given in model-based techniques for predictive control. However, also data-based methods can be applied for the development of implicit models (e.g. neural networks for forecasting the power demand of a cluster of loads [8]). Ongoing research involves the experimental verification of the proposed node architecture and simulation studies about the convergence of the demand response system, under different aggregation levels of distributed resources. A first experimental verification of the proposed control concept is discussed in [9], where a developed MPC scheme for a domestic freezer is presented for real-time demand response applications.

V. Conclusions

A novel control scheme for automated demand response mechanisms is proposed, which introduces uniform interfaces for heterogeneous resources, automated functions and distributed intelligence. The proposed control scheme reflects a decentralised approach for the management of distributed energy resources under a global coordinator, the aggregator. Distributed computer algorithms create predictions and define control inputs in a decentralised fashion based on local optimisation processes that explicitly take into account the constraints related to physical limitations and users' preferences. Automated demand response mechanisms refer to an automated notification process between system operators and system users. Considering an advanced sensing and communication infrastructure, automated functions can be effectively designed that require minimum user intervention. The elucidated ideas in this paper reveal an alternative approach for price-based demand response and for demand side management of residential customers.

VI. Appendix A. Simulation pseudo code for the planning phase

VTN is the aggregator, and VENj the system users. Current time is two hours before the GCT of the day-ahead market, while $\tau=4$ (sec.), $\tau_s=900$ (sec.)$=15$ (min.), and $m=96$. Each individual VENj informs the VTN about its day-ahead predicted positions.

1. Each individual VENj, where $j=1,\ldots, N$, calculates and forwards the reference trajectory $r_j(k_d+i-1|k_d-i_p)$, where $i=1,\ \ldots,\ n$, to the VTN;

2. The VTN calculates the sum $\sum r_j(k_d+i-1|k_d-i_p)$ for $j=1,\ldots, N$;

The VTN creates aggregate order books and submits those to the day-ahead market operator.

Moving closer to the beginning of the operational day d by one hour, i_p is reduced by 900, given that $\tau=4$ (sec.).

3. $i_p=i_p-900$;

After the GCT, the day-ahead market operator informs the aggregator about market clearing volumes and prices. Then, the aggregator calculates and submits to the TSO the complete energy schedule $p(l)$ for the day ahead.

4. $i_p=i_p-900$;

Each VENj informs the VTN about its energy capabilities for ancillary services (e.g. provision of operating reserves).

The VTN collects information from each VENj, creates aggregate bids for secondary reserves, processes them and eventually submits bids, in the form of a piecewise constant function $q(l)$, to the TSO.

5. The VTN submits the aggregate bids for operating reserves $q(l)$.

VII. Appendix B. Real-time simulation pseudo code

Current time instant $k=k_d$, $\tau=4$ (sec.), $n=21\ 600$, $\tau_{horizon}=10\ 800$ (sec.) $=180$ (min.), $i_{horizon}=2\ 700$.

1. The VTN obtains the output measurement $y(k)=\Sigma_j(y_j(k))$;

2. The VTN defines and broadcasts the processed set-point trajectory $s(k+i|k)$ to all associated VEN in the considered control area;

3. Each associated VENj obtains the set-point trajectory $s(k+i|k)$;

4. Optimisation of the j-th VEN: Each individual VENj checks (based on predictions over the control horizon $k+i$, where $i=1, 2,\ldots, i_{horizon}$, and $i_{horizon}\leq n$) if it can partially contribute to the received trajectory $s(k+i|k)$, then calculates and forwards to the VTN the reference signal $r_j(k+i|k)$, where $i=1, 2,\ldots, i_{horizon}$, about the part that can be fulfilled;

5. The VTN obtains the reference signal $r_j(k+i|k)$ from VENj, performs consistency checks (e.g. overshooting avoidance) and sends back a binary signal notification signal $w_j(k)\in\{0,1\}$ to indicate rejection or acceptance with respect to $r_j(k+i|k)$;

6. In case of acceptance of the reference signal $r_j(k+i|k)$, the VENj chooses the input trajectory $u_j(k+i|k)$, where $i=1,\ldots, i_{horizon}-1$, and performs the control actions by applying the next input $u_j(k)=u_j(k|k)$ to the j-th process;

7. $i=i+1$;

8. The VTN obtains the output measurement $y(k+1)=\Sigma_j(y_j(k+1))$;

9. The VTN subtracts the fulfilled actions, based on the sum $\Sigma_j r_j(k+i|k)$, recalculates and forwards the updated processed set-point trajectory $s(k+1+i|k+1)$ and the whole process is repeated.

In the situation that the state of an individual VENj has changed considerably, following the last optimisation (i.e. after applying the input trajectory $u_j(k+i|k)$), then the VENj recalculates its future energy capabilities for ancillary services (e.g. updated bids for operating reserves) and informs the aggregator;

The VTN collects all information, creates aggregate bids for secondary reserves, processes them, and submits updated bids to the TSO, if necessary, in the form of a piecewise constant function $q(l)$.

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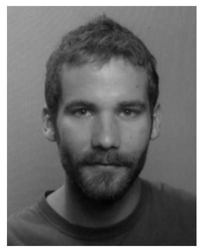
IX. Biographies



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Since 1993, he has been a part-time professor in the Department of Electrical Engineering at Delft University of Technology, in the field of power systems engineering. Since 2008, he has been a Full-Time Professor at Eindhoven University of Technology, where he is leading research programs on distributed generation, integration of wind power, network concepts, and reliability.

Prof. Kling is involved in scientific organisations, such as CIGRE and the IEEE. As Netherlands' representative, he is a member of CIGRE Study Committee C6 Distribution Systems and Dispersed Generation and the Administrative Council of CIGRE.