Evaluating the DSO role in Automated Demand Response and Distributed Energy Resources: Flexibility4Chile Project

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The mission of Distribution System Operators (DSOs) is to operate and manage distribution networks in a safe and secure manner. They are also responsible for developing distribution grids to ensure the long-term ability of the system to deliver high-quality services to grid users and other stakeholders of the electric power system.

Traditionally, DSOs have carried out their mission with adequate network operation and planning. However, the profound transformation of the energy system that is currently taking place worldwide creates new challenges for DSOs to carry out their responsibilities in a cost-efficient and secure manner. A significant amount of renewable energy sources (RES) is already connected, and more is expected in the future. Furthermore, the number of electric vehicles (EVs) and public charging stations will see a major increase in the coming years. These trends are coupled with an exponential technological evolution that allows for decentralized energy sources to be connected at lower voltages, and at the same time, enables customers to interact with the market in response to grid conditions.

The current scenario raises serious problems for power grid stability. As an example of these problems, which can be compensated by flexibility sources (i.e. batteries), are the integration of renewable energy resources or emergency scenarios, and performed transparently according to grid conditions. Thus, beyond that, electrification grows constantly due to the introduction of new devices and appliances with better performance, increasing the complexity and uncertainty due to changing consumption patterns (particularly those coming from mobile loads such as EVs), creating more generation imbalances. Additionally, Volt-VAr control and congestion management are important concerns, requiring intelligent devices to improve control over the power grid, and at the same time SCADA systems must add specific interfaces and protocols to allow for the control of these new devices. Updating standards is one of the main ways to solve these issues. Solutions to the new problems facing the grid include: updating standards, improving flexibility (including the capacity to adjust loads), and adjusting power generation and storage in real time. It is important that the behavior of flexible resources (FR) be continually adapted to grid conditions.

FR can be owned either by the utility or a customer. In the first option, the utility could operate and use its resources intentionally, as one more part of its current infrastructure. This scenario is possible in many regions, including the Latin America (LATAM) market. However, European regulations are more restrictive, and expressly DSOs may not own, develop, manage, or operate energy storage facilities. In some specific cases, European Union Member States may allow DSOs to own and operate energy storage facilities, where they are fully integrated network components and the regulatory authority has granted its approval, as it is states in the European Directive 2019/944. Therefore, in European grids, FR based on storage will be provided by market companies, while FR using demand response technologies will be provided by customers and/or aggregators, such as retailers, Flexibility Service Providers (FSP), smart-business parks, electric vehicle fleet management platforms, etc.

Thus, the new Flexibility Services (FSs) should be organized to guarantee service payment and flexibility management. Globally, at the distribution level, two main relationship models are emerging for FS operations: a direct DSO-Customer relationship or a DSO-FSP relationship in which the FSP could manage different customers' assets. However, the European Commission permits only DSO-FSP operations, and does not permit direct DSO-Customer operations. At the European Union level, the general rules that those services must accomplish were recently established, although there are different models that could be applied at a national level. The European Commission has made its preference for a market-based schema to regulate flexibility transactions (EU Regulation Act 2019/944, complemented by 2019/943).

The different relationship models amongst TSO, Balance Responsible Party (BRP is a market participant or its chosen representative responsible for its imbalances in the electricity market), DSO, and customers, are defining different market models. These markets facilitate tasks related to planning, control, validation, dispatch, invoicing, etc., but, in the European regulations, some different actors have specified roles within markets. This fact provides several legal scenarios according to the European regulations: separate TSO & DSO congestion management markets, a combined TSO & DSO market, or a combined balancing and congestion management market. Each of these options poses different challenges. There are different European initiatives researching and developing different market models at the national level. Additionally, the market structure determines the interaction level amongst actors in a market. For example, in Spain and Portugal (Iberian Peninsula), the Nominated Electricity Market Operator (NEMO) is OMIE, running both a day-ahead market and an intraday market. This is one of the most common approaches. However, there are other types of markets, like a distributed market with peer-to-peer transactive energy, which are emerging. In this sense, some research lines and international initiatives are researching the application of new technologies, such as blockchain, to energy markets in order to improve cybersecurity and reliability.

In summary, FRs are needed for congestion management in order to improve the quality of service in DSO grids. In this sense, different scenarios strongly conditioned by regulations are possible. According to the European regulations, a DSO cannot own and control DERs (i.e. storage, RES, demand response, etc.) directly unless authorized by National Regulatory Authorities (NRA). However, other markets with less restrictive regulations (i.e. the LATAM market) could be more open to agile innovation, providing the opportunity to test different technology and their advantages in DSO power grids directly by the DSOs, not necessarily requiring the presence of aggregators nor other third parties in the process.

Flexibility Management

The penetration of renewable energy, batteries, and electric vehicles with Vehicle to Grid (V2G) technology will make management of the power grid very difficult. Distributed Energy Resource Management and Congestion Management are especially important for renewable integration, since the availability of renewable energy sources is strongly dependent on weather. Batteries can soften this effect. However, batteries have limited capacity and require complex management to achieve optimal benefit. Both renewable generation and batteries could be spread throughout the entire distribution network, including both primary distribution (at medium voltage) and secondary distribution (at low voltage). Additionally, at the secondary distribution level, EVs with V2G technology will be an additional concern in smart grids since they may function either as load or as a mobile "battery with wheels". Specifically, congestion management is one of the main concerns of distribution companies, which must be able to manage the energy and status of grids without the direct control of energy generation. If the Aggregators were to provide FSs, it would be possible to establish a coordinated and distributed congestion management process. Thus, the DSO would orchestrate the congestion management, exchanging rules and information with the Aggregators. In this case, a local market based on capacity would support interoperation between DSO and the Aggregators, establishing the value of interoperation by balancing out awards and penalties.

The recent European regulation about energy markets has placed DSOs in an intermediate position between TSO and consumers. However, the new technologies based on batteries, EVs, renewable energy, etc. have modified the way in which energy is managed, and also have provided new methods to guarantee proper power supply, even in emergencies. There are three main emergency cases for the distribution system:

- Communication breakdown. Smart Grids combine Information and Communication Technology (ICT) with new power generation, storage, and demand response technologies. Such systems could experience communication breakdowns due to cyber-attacks, faults in the communication devices, or programmed communication interruption according to maintenance and updating processes.
- Energy supply breakdown. This is the traditional fault provoked by a lack of maintenance, deterioration, illegal manipulation, accident, natural disasters, or cyber-attacks.
- Both communication breakdown and energy supply breakdown. This is the worst scenario. The breakdown of both systems requires the assistance of intermediate systems or aggregators, which take control and perform various procedures to restore both services.

The FSPs use the available DERs (RES, storage, V2G) and customer load to better operate the DSO grids. The implementation of a local market to gather and transmit information for the FSP will enable the interoperation between the parties (TSO, DSO) and different service providers. Of course, the local market will reward behavior intended to reduce congestion according to grid requests. Thus, in a local market oriented to congestion management based on flexibility services provided by Aggregators, standard protocols such as OpenADR ensure resource control and information exchange. This provides a scalable and reliable strategy for the DSO to ensure continuity of power quality and supply using distributed congestion management.

The OpenADR standard protocol and other alternatives

The OpenADR is a standard protocol developed by OpenADR Alliance. This protocol provides a Demand Response solution for asset management (including aggregators). This open standard is based on “Energy Interoperation 1.0” from OASIS (Organization for the Advancement of Structured Information Standards). However, Energy Interoperation (EI) includes other additional services, which allow this protocol to implement a transactive energy strategy.

The architecture of the OpenADR protocol is based on a hierarchical organization of different nodes in which a Virtual Top Node (VTN) could control one or several Virtual End Nodes (VEN). At the same time, one VEN could act as a final node or as an Aggregator, which would adopt a VTN role for other VENs in the hierarchically lower layer. Fig. 1 shows an example of this hierarchical architecture. In this schema, the OpenADR protocol only allows a tree-based schema. In this way, a VEN could be placed either at the head of a Smart Building or a complete Power Grid, since the services are the same and take effect in all aggregated resources. Thus, each aggregator level simplifies the downstream control and regulation of available resources. This concept is similar to the concept of Virtual Power Plants (VPPs), simplifying the management of the power grid. A Virtual Power Plant is a system that integrates several types of power resources to give a reliable overall power supply, to provide ancillary services to grid operators (for grid stability), and as a cloud-based central or distributed control center that takes advantage of ICTs. In this sense, both strategies provide high scalability and reliability, simplifying the complexity of the power grid.

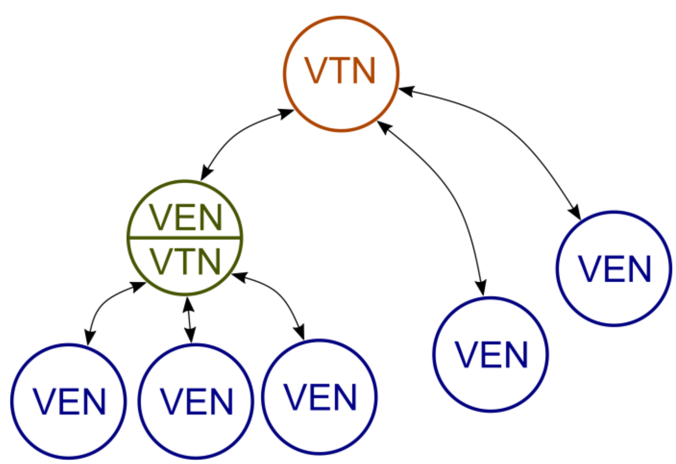

Fig. 1. Hierarchical relation between a Virtual Top Node (VTN) and Virtual End Nodes (VENs) in an OpenADR for distribution system management.

The main objective of OpenADR protocol is the management of a good. Of course, this good is primarily active power, but it is possible to manage reactive power, capacity, other characteristics of power supply, or even goods outside of the electric energy business, such as water or gas. The available documentation about OpenADR protocol is completely oriented to the electric energy market. In this way, the OpenADR protocol is the first try to get an implementation of EI oriented to the electric energy market.

OpenADR has five main services:

- **Registration message (named EiRegistration according to the OpenADR terminology):** used in the joining process between a VEN and a VTN
- **Event message (EiEvent):** allows flexibility requests to be sent to VENs
- **Reporting message (EiReport):** allows sharing information among OpenADR nodes
- **Opt message (EiOpt):** used by the VEN to confirm or deny a request and to share the availability of the node to receive requests
- **Pull mode message (OadrPoll):** used to know the VEN status (only used in PULL mode)

The OpenADR and EI standards are harmonized with other standards (Fig. 2) from the International Electrotechnical Commission (IEC). For example, the 61968 (Common Information Model/Distribution Management) and 61970 (Common Interface Model/Energy Management) standards address the Common Information Model (CIM) and the Component Interface Specification (CIS) for Distribution Management System (DMS) and Energy Management System (EMS). The eMIX (Energy Market Information Exchange) standard (from OASIS) is the information standard related to OpenADR and EI standards. The eMIX is interoperable with the other protocols from IEC and IEEE. The main difference is that IEC CIM stores the period registering the start and end date and hour (timestamp) and the eMIX registers the initial timestamp and the duration. Additionally, there is a high degree of interoperability with other protocols like IEEE 2030 (Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System, and End-Use Applications and Loads) and IEC 62325 (Framework for energy market communications).

Additionally, the OpenADR and EI standard protocols are open standards, but the standards from IEEE and IEC are not available for open access. Although OpenADR is an open standard, the cybersecurity implemented in this standard is sufficient to operate in power grids and avoid cyberattacks. Standard security is mandatory and adopts TLS for establishing secure channels between a VTN and a VEN for communication. In high security mode, the standard adopts an open architecture for security and will not restrict itself to some specific or proprietary technologies. Fig. 2 summarizes the Smart Grid Standards roadmap involved in ADR. All of these standards take an important role in the standards roadmap of the main organizations and countries on strategies related to energy.

The OpenADR standard protocol simplifies the management of DR, making the process easier than implemented in IEC and IEEE protocols. The functionalities of IEC and IEEE protocols are wider ranging and more specific than OpenADR. However, the OpenADR functionalities may involve several IEC or IEEE functionalities, because the OpenADR has a high level of encapsulation. However, the question is whether the congestion management functionality provided by OpenADR is enough to solve the problem of Automated Demand Response, following the Occam’s razor principle that the simplest explanation is often the best one.

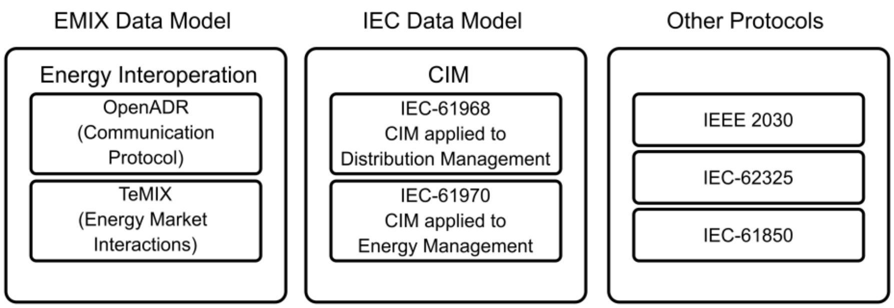

Fig. 2. Smart Grid Standards Roadmap involved in Automated Demand Response.

The Flexibility4Chile Project

The Flexibility4Chile project is intended to test:

- The connectivity between DSO and customers (by means of aggregators or directly) based on standard protocols, like OpenADR (Open Automated Demand Response) from the OASIS organization.
- The benefits of these initiatives for congestion management and network quality.
- New strategies, use cases, and technical requirements for demand response and distributed energy resource integration using smart grid assets, such as smart inverters, energy storage, and other controllable loads.

The project was developed in two stages. In the first stage, the project has been deployed at the Enel Smart Grid Building (SGB), shown in Fig. 3, a modern building located in the Business Park of Huechuraba in Santiago de Chile (Chile). This building is an attempt at a complete demonstration of smart grid new technologies, showing the potential of smart meters, renewable energy and electric vehicle grid integration, and flexibility programs. The building has PV generation, electric recharging point, and a whole set of controllable loads, such as the heating, ventilation, and air conditioning (HVAC) and lighting systems.

Fig. 3. Enel Smart Grid Building (Santiago de Chile, Chile)

In the second stage, the project tested the OpenADR protocol in an alternative location at the Savona Campus of the University of Genoa (Italy). The project was a successful collaboration between enterprises and universities to develop a Proof of Concept (PoC) in the context defined in Fig. 4, but without TSO involvement. The hierarchy of the PoC involves Enel as a DSO, funding organization, and project coordinator, and the Electric Power Research Institute (EPRI) as technology and strategy adviser. The University of Seville (Spain) developed the Demand Response Management System (DRMS) based on Capacity Bidding Program (CBP). The Maps Group (a technology company from the north of Italy) developed and deployed the aggregator platform to provide flexibility services. The aggregator controls the customers' facilities, in this case, the Living Lab, deployed at the Savona Campus. The Living Lab is a real microgrid test bed in an experimental Smart Grid environment where the innovation initiatives can be tested. The main objective is the generation of new products, services, infrastructure, and knowledge to meet society's needs.

The objective of the second stage is to show the viability of OpenADR to implement an infrastructure to control congestion management by using local market integrating aggregators, which provide flexibility services according to the grid conditions. Thus, the University of Seville plays the DSO role by developing a VTN and a DRMS, Maps Group plays the role of a Flexibility Service Provider or aggregator, and the University of Genoa plays the role of a prosumer.

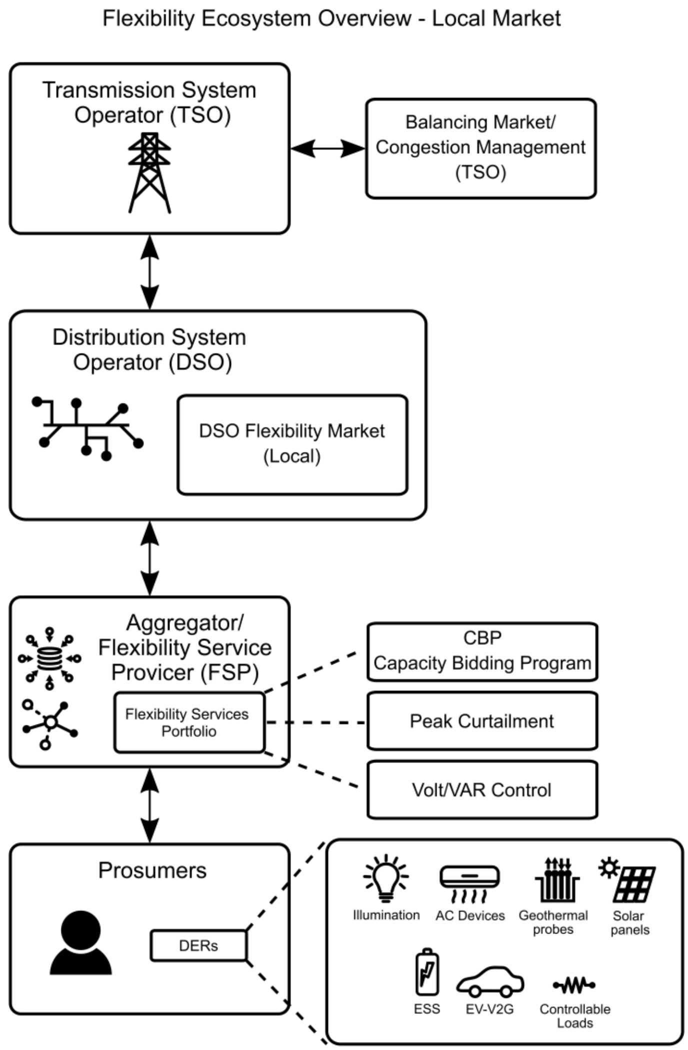

Fig. 4. Hierarchy of the proof of concept (PoC) at the Savona Campus of University of Genoa, Italy. This is a successful collaboration among enterprises and universities.

Capacity Bidding Program (CBP)

A Capacity Bidding Program (CBP) is a Demand Response (DR) program that suggests various product options to market participants by which they can earn incentive payments in exchange for reducing energy consumption when requested by the utility.

CBP and DR program participants may include large customers (e.g. industrial customers), and aggregators. In this context, an aggregator is defined as a third-party entity that combines the load of one or more utility customer service accounts to participate under this schedule.

Although the programs implemented by U.S. utilities San Diego Gas & Electric (SDG&E) and Pacific Gas & Electric (PG&E) were applied to residential consumers in addition to industrial customers, they are very good examples of the application of CBP in energy markets.

A CBP implies an information exchange between a customer (or an aggregator) and a utility. Traditionally, the best ways to exchange information and commands were at best partially automated, such as email, web forms, phone calls, etc. In a CBP, the OpenADR standard protocol is the main communication method. OpenADR contains a series of signals/events and data reports to implement DR programs, so it could be used to implement communication channels and establish the methods and format of information flow between the utility (Virtual Top Node, VTN) and a customer/aggregator (Virtual End Node).

This architecture implies the installation of a VTN in Seville and a VEN in Savona Campus, specifying the information that must be exchanged between them. The VEN offers different flexibility services based on the available resources. The VTN gathers this information and, supported by the DRMS, requests the flexibility services by sending messages. The messages, which are used to request flexibility services, are named events in the OpenADR standard.

Savona Campus

In the Customer domain, Savona Campus carried out a “Smart Polygeneration Microgrid” (SPM) (Fig. 5): a 3-phase low voltage “intelligent” distribution system running inside the campus and including: micro-cogeneration gas turbines, photovoltaic (PV) fields, absorption chillers, an electrical storage system, standard electrical vehicle, V2G charging stations, and a gas boiler. A “Smart Energy Building” (SEB, fig. 6) equipped with a BMS (Building Management System), a geothermal heat pump (GHP), and a PV field is directly connected to the microgrid. The BMS is connected to a number of controllers installed in the SEB, which are in turn connected to all field sensors and actuators (lighting control, presence and temperature sensors, GHP and air handling unit, etc.). The controllers are interfaced via BACnet (Building Automation and Control Networks). BACnet is a data communication protocol for building automation and control networks, developed under the auspices of the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE).

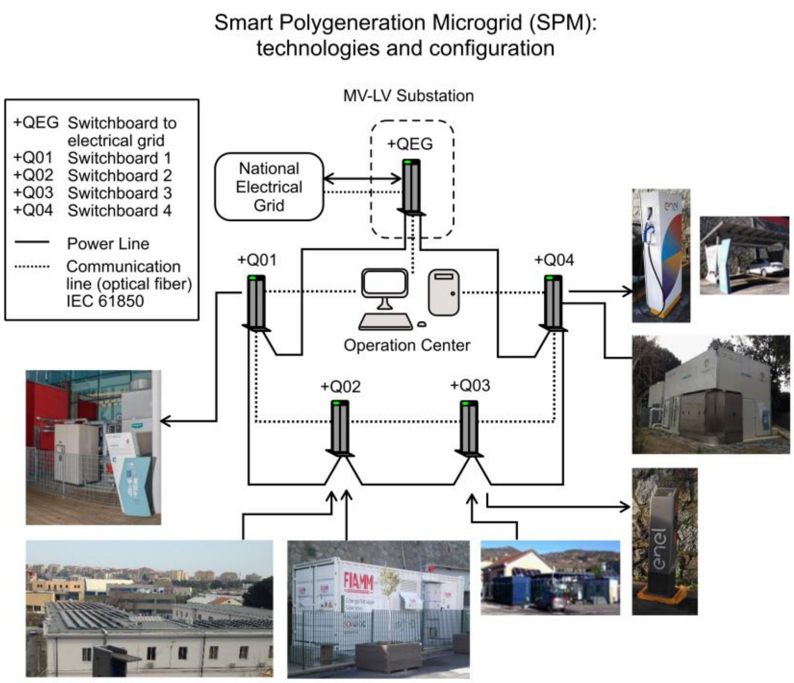

Fig. 5. Smart Polygeneration Microgrid (SPM).

Fig. 6. The Smart Energy Building at the Savona Campus (University of Genoa, Italy)

The microgrid is also connected to the pre-existing campus electricity network feeding the campus buildings, shown in Fig. 7. The geothermal heat pump installed on the SEB typically consumes up to 15 kW and can be remotely controlled via BACnet, and thus can be exploited as a controllable load.

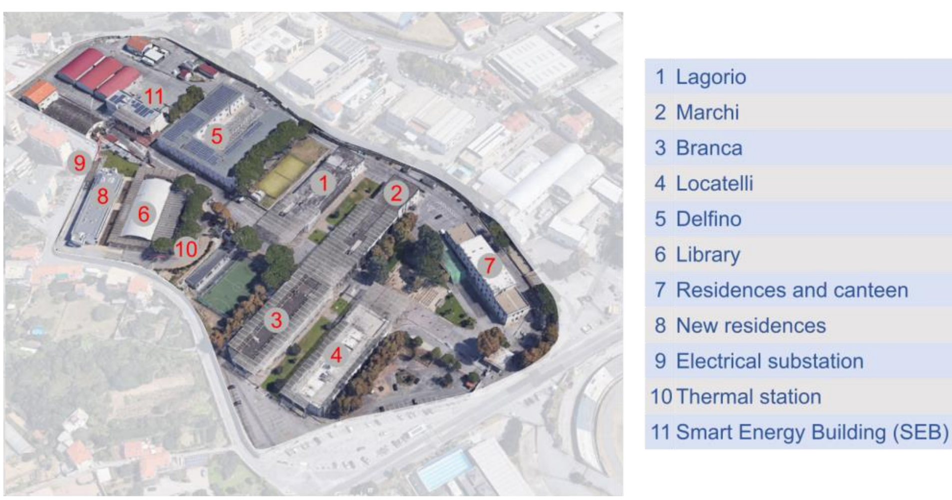

Fig. 7. Savona Campus buildings (University of Genoa, Italy).

Demand Response Management System and Virtual Top Node

The developed and deployed infrastructure shown in Fig. 8 as a result of the described project is the implementation of the PoC. The VTN and the VEN shares data between the aggregator and the DSO by means of the OpenADR protocol. Initially, the flexibility request (events) are generated by a local system because the system is not yet connected with the DSO infrastructure. The VEN has an Aggregator Platform, which dispatches resources involved in the demand response program and sends the required commands to comply with the DR Program. All these systems are included in a Virtual Private Network (VPN) in order to maintain a high level of cybersecurity.

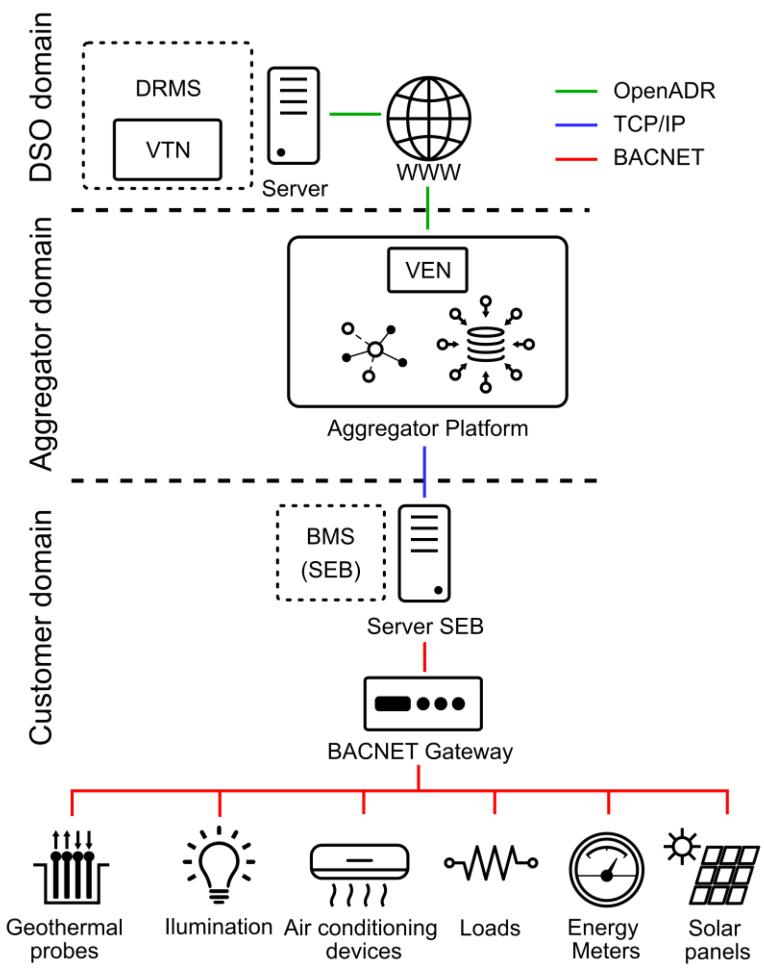

Fig. 8. Scheme of Proof of Concept (PoC). DRMS, Demand Response Management System; VTN, Virtual Top Node; VEN, Virtual End Node; BMS, Building Management System; SEB, Smart Energy Building.

In this project, the VTN platform is located at the University of Seville and the VEN platform is located at the Savona Campus. The Aggregator Platform was developed and deployed by MAPS

Company. Of course, security is another important concern. In this PoC, the security constraint is implemented based on the deployment of a Virtual Private Network (VPN) and the manually pre-registration of VENs in the VTN. Thus, the VTN only allows the pre-registered VENs to take part. Additionally, the IP and VTN are pre-registered in VENs that will take part in the process. One of the future lines is to increase cybersecurity in order to provide better and more reliable operation modes of OpenADR and EI protocols.

Additionally, a local VEN is connected to the University of Seville's infrastructure. This VEN is managing a Smart Grid lab with several technologies.

Although the DSO actions were simulated, the platform associated to VTN was designed modularly in order to provide a Demand Response Automated Server (DRAS), to be independent from the DSO platform. In addition, the VTN and the DRMS are designed as independent modules. Thus, different types of DRMSs could use the same VTN. The VTN shown in Fig. 9 provides different APIs, some of which are oriented to serve VENs and others to serve higher systems like DRMS. The API includes different service sets offered to the VTN clients (DSO platform and DRMS), as described previously in OpenADR Standard section. Additionally, the VTN maintains the configuration of the VTN in a cache memory, and, in case of a fault, the system could get the most recent information from the Persistence Layer Manager, which is a hard disk and persistent copy of the status of the VTN. The VTN is completely developed in Java.

The Cache Memory Manager uses an information standard to maintain the VTN's information to allow for the correct operation of the system. The Persistence Layer Manager works in the background in order to reduce the influence over the operation of VTN (decreasing the computational resources consumption).

The Persistence Layer is based on different technology, in order to check what the best option is in this type of scenario. This technology works in different parts of the process, storing the information in different stages of the process.

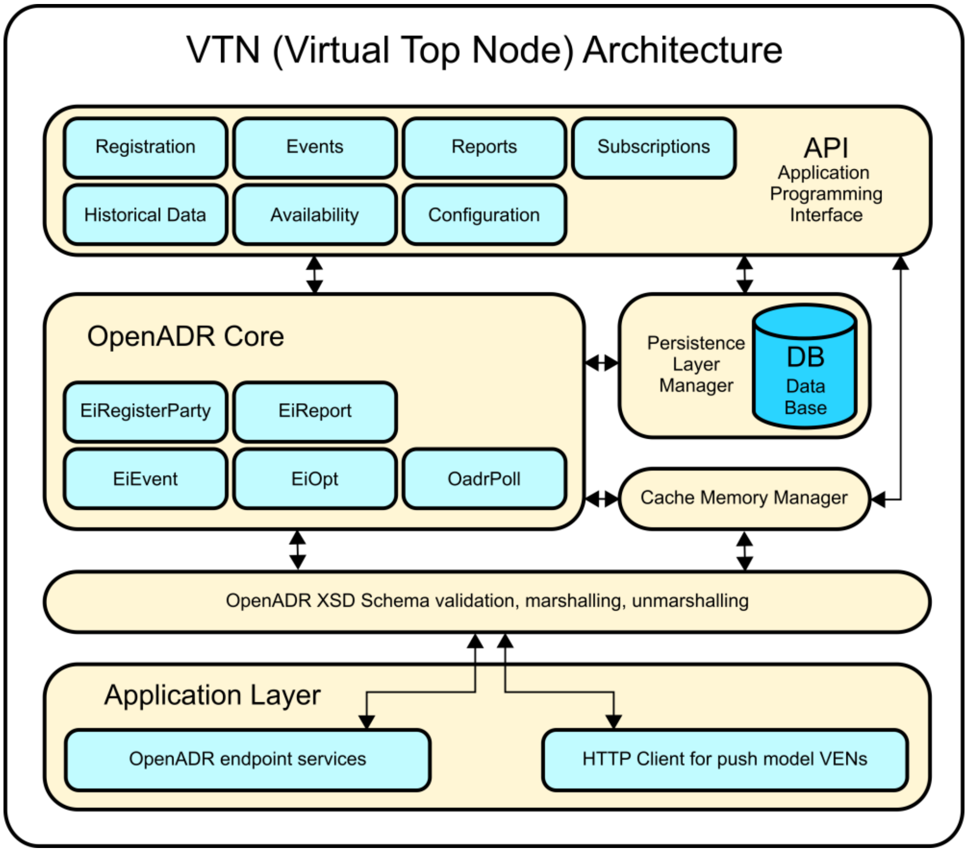

Fig. 9. VTN Architecture.

The DRMS is deployed over the VTN, providing an interface to administrate the VTN. The DRMS involves all the available services in the VTN, and it allows the DRMS to send any command or request to one or more VENs registered in DR programs.

Testing Proof of Concept

Several tests performed in the PoC showed that the flexibility services could provide a new method for congestion management and grid control. Table I shows the results of some of the tests performed during 2018 in the PoC. The results show a reduction of around 50% in consumption in the periods in which the flexibility services are running, these periods are specified in Table I. The flexibility service has provided the possibility of congestion management, and in a scenario with several VENs it would be possible to control several resources, implementing distributed energy resource management strategy control. In Table I, there are several columns:

- Trigger Date contains the day in which the flexibility service was configured.
- Trigger Hour is the hour in which the flexibility service was configured.
- Duration in minutes is the duration starting at Trigger Hour. This term is referenced as Offer Duration in Fig. 10.
- Offer describes the energy reduction bid in Wh. This term is referenced as Reduction Offer in Fig. 10.
- Forecasted Consumption provides the expected energy consumption in Wh.
- Real Consumption provides the final energy consumption in Wh in the period when the flexibility service is active.
- Reduction describes the reduction provided by the application of the flexibility service, according to the Forecasted Consumption. This reduction is provided in Wh and percentage over the Forecasted Consumption.

Table I.
Selected real test performed with the PoC.

Trigger Date (2018)	Trigger Hour	Duration (min)	Offer (Wh)	Forecasted Consumption (Wh)	Real Consumption (Wh)	Reduction (Wh)	Reduction (%)
Dec 10th	17:00	60	8,510	8,330	4,100	4,230	50.8
Dec 11th	None	-	-	-	-	-	-
Dec 12th	16:00	60	5,320	9,209	4,190	5,019	54.5
Dec 13th	19:00	60	4,260	6,720	3,870	2,850	42.4
Dec 14th	12:00	90	4,970	8,880	2,275	6,605	74.4

These tests were conducted to test the suitability of the corresponding properties of OpenADR to implement a CBP. In the test case, the PoC supports the normal operation of the grid, harnessing flexibility from the aggregator. The future second stage is to determine, in a real scenario with a high penetration of RES and Smart Grid technology, whether the protocol could operate for congestion relief. The CBP manages the capacity by creating events with consumption constraints, according to the two pieces of information reported by aggregators (which implements VENs): reduction offer and offer duration (Fig. 10). The VTN gathers additional information: temperature, humidity, and cloud cover (Fig. 11). Additionally, the aggregators send consumption forecasts (Fig. 12). The consumption forecast at the aggregators' level is more accurate and provides higher confidence values than that at the individual grid participant level (Fig. 13). The DSO should audit the forecasting and consumption in order to verify the consumption and check grid stability. Fig. 13 shows the mean power forecasting and the real mean power registered. The power forecasting does not keep in mind the variations provided by the flexibility services. Thus, there are several periods (specified in Table I) in which the registered mean power is lower than the forecasted mean power.

The CBP takes advantage of the data provided by aggregators to design strategies for consumption reduction. Thus, the DSO sends requests (events in terms of OpenADR terminology) with specific restrictions or DR programs to different aggregators. The aggregators could operate or not within the DR Program proposed in the event, according to the request based on the feasibility to provide the service. The CBP proposed has some constraints: reduction offers can be sent by the aggregator for any hour of the day and week, reduction offers must be sent by the aggregator one day ahead, maximum of four events per week, maximum of one event per day, minimum of ten hours between events, the events must be notified by the VTN three hours prior to the start of event and the confirmation must be notified by VEN one hour prior to the start of event, the starting and duration of the event must be according to the reduction offer and offer duration, and the value of reduction requested must be less than or equal to the value in the load reduction offer. In the tested cases, the aggregator is enrolled into the DR program and provides a consumption reduction of about 50% in each performed test. The event status and the consumption are shown in Fig. 14 in green and red colors, respectively. The event status shows the period in which the VTN requested the reduction (sending an event message) according to the reduction offer and offer duration specified by VEN. Thus, Fig. 14 describes a scenario in which the aggregator took part in the event, reducing the customers' consumption. At the same time, the aggregator managed DER resources within the Savona Campus in order to cover customer consumption in real time.

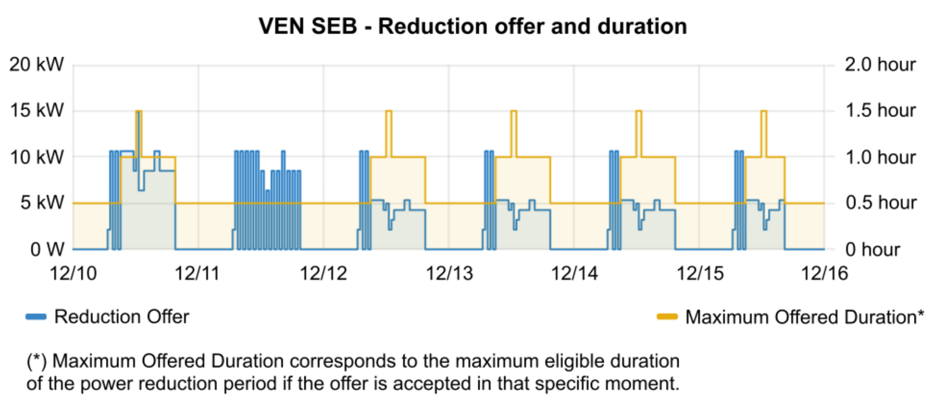

Fig. 10. Load Reduction and offer duration on the test period. VEN, Virtual End Node; SEB: Smart Energy Building.

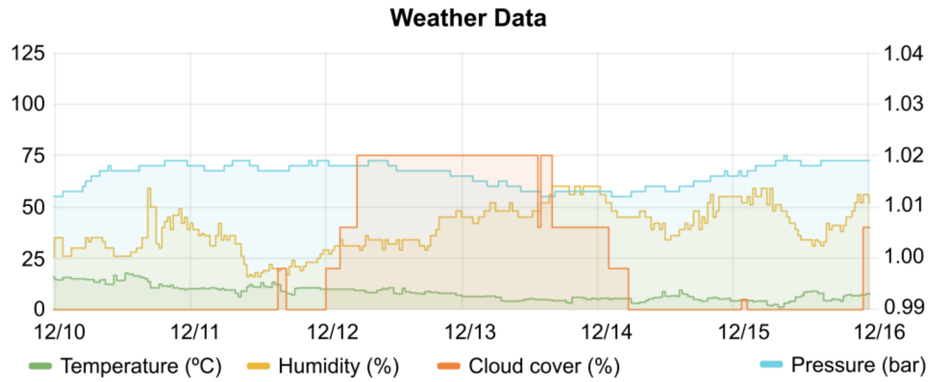

Fig. 11. Temperature, humidity and cloud cover during the test period.

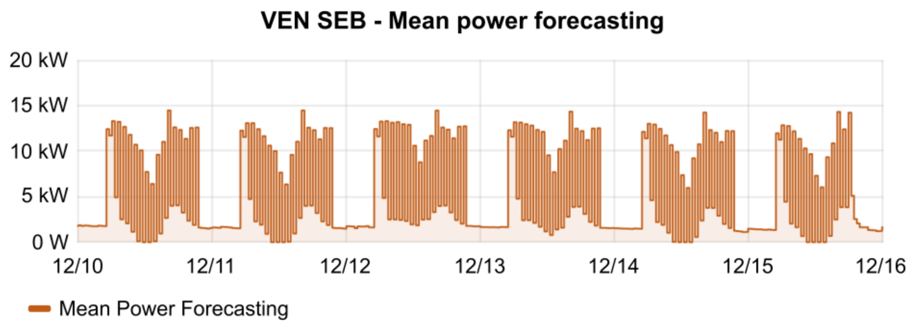

Fig. 12. Consumption forecasting during the test period. VEN, Virtual End Node; SEB: Smart Energy Building.

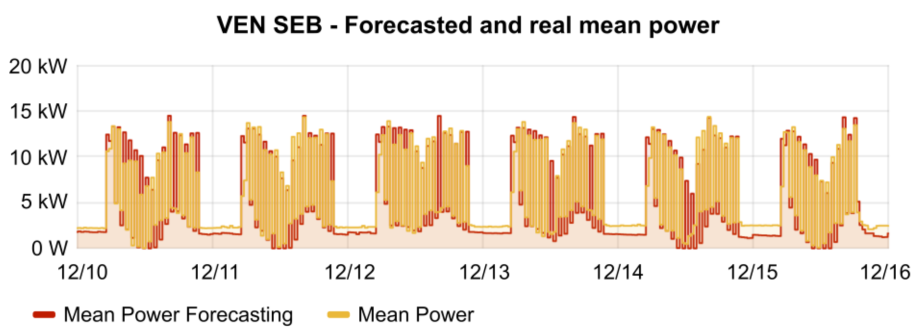

Fig. 13. Consumption forecasting during the test period. VEN, Virtual End Node; SEB: Smart Energy Building.

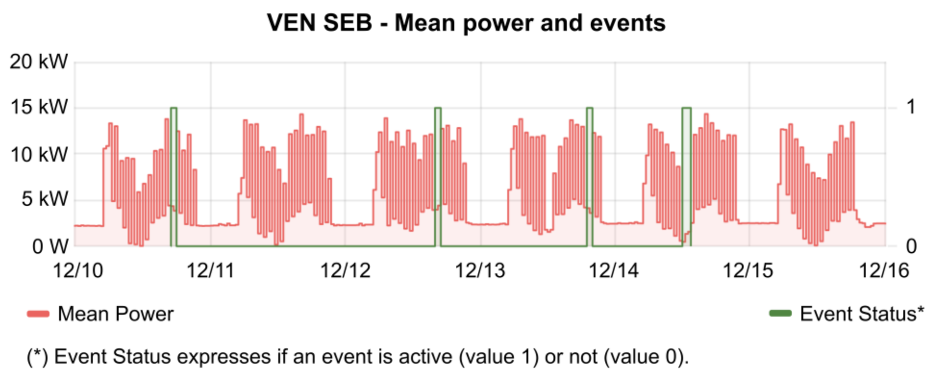

Fig. 14. Mean power and event status during the test period. VEN, Virtual End Node; SEB: Smart Energy Building.

Figures 15, 16, and 17 contains the detailed graph of the test corresponding to December 14th. The consumption forecast is around 10 kW, decreasing between 12:00 and 14:00 (Fig. 16. The reduction offer (Fig. 15) was near 5 KW. The offer duration increases in the period between 12:00 and 13:00, and the mean period of offer is 1 hour. Thus, the DRMS (from DSO and through VTN) proposes a reduction between 12:00 and 13:30 (Fig. 17) to the Aggregator (VEN), taking advantage of the maximum reduction of consumption. Thus, the Aggregator provides a reduction of consumption either by dispatching alternative energy resources or by temporally reducing (or disabling) the consumption of some assets. Variability of consumption is due to the nature of the SEB's assets. This building has GHP, which is the main source of energy consumption since the pump needed to move the liquid around proves are used once an hour in winter to heat the building. Additionally, the information reported by the Aggregator is the average power consumed in the last 30 minutes.

In this CBP, the DSO is only requesting an event with the data provided by the aggregator regarding the availability of flexible resources. The aggregator is in charge of performing the curtailment, fulfilling the requirements established by the DR Program for the event. When the event is triggered the consumption decreases according to the constraints established by the CBP event, guaranteeing the correct operation of the power grid. The event in the OpenADR protocol allows the DRMS (in the DSO platform) to define a ramp up period, in which the aggregator platform performs the necessary actions to comply with the event restrictions, because some operations could involve a complex actuation to provide the consumption reduction during the event duration after the ramp up period.

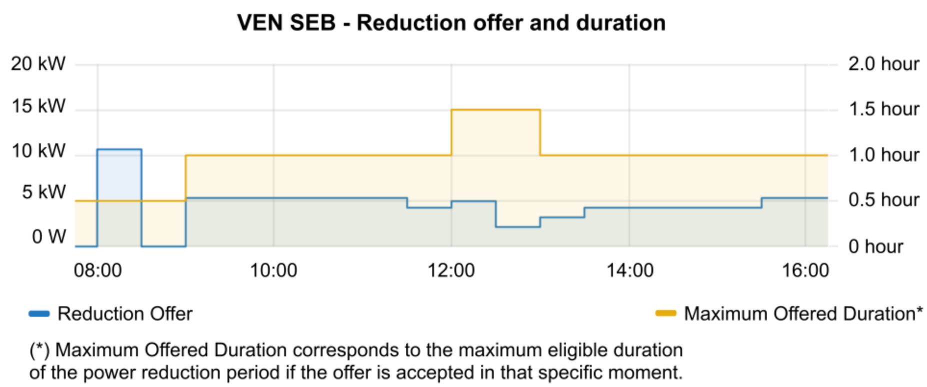

Fig. 15. Reduction offer and offer duration for December 14th test. VEN, Virtual End Node; SEB: Smart Energy Building.

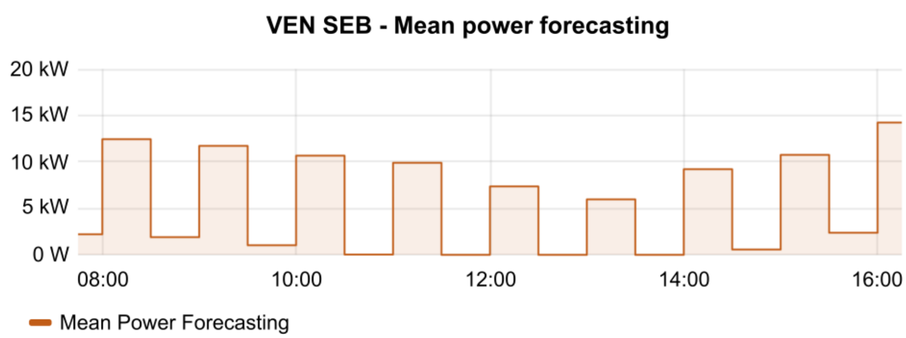

Fig. 16. Consumption forecasting for December 14th test. VEN, Virtual End Node; SEB: Smart Energy Building.

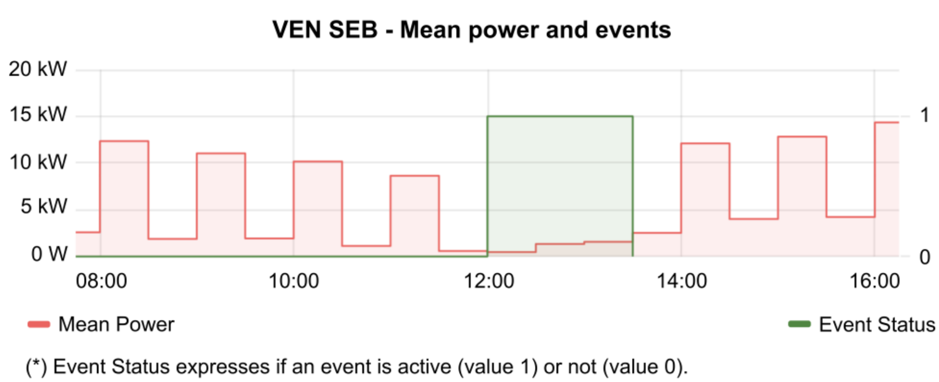

Fig. 17. Mean Power and event status for December 14th test. VEN, Virtual End Node; SEB: Smart Energy Building.

The PoC provided a successful integration of different platforms, with the only nexus based on the OpenADR standard. Using OpenADR at the DSO level can be helpful for several crucial tasks, including: grid emergency response, congestion management, regulatory issues, DER management, and the future scenario of smart grids.

The Future of DSOs in the European energy market

Although there are some regulatory issues to be tackled at the Member States level, DSOs are faced with new challenges in the energy transition, including: increased RES integration; electrification with EVs; heating and cooling; and meeting de-carbonization objectives. A more flexible and resilient grid is required to face these new challenges, with different actors operating and exchanging information.

The complexity of bidirectional power flows, reactive power, Volt/VAr control needs, and other factors in system stability are creating scenarios in which the implementation of markets to purchase "flexibility" coming from aggregators should be structured to address emergency situations due to weather conditions or other hazardous events, grid congestion, etc.

It is very probable that in the near future, transmission system operators (TSOs) could harness the flexibility offered by numerous DERs as part of grid management under normal conditions. This would require that the right stakeholders, systems platform, and procedures are defined and established to create a "flexibility and ancillary services" market.

In all the aforementioned scenarios, congestion management is an unavoidable responsibility for DSOs. DSOs will have to perform congestion management based on market conditions and standard protocols, such as the OpenADR with CBP program demonstrated in this article. The functional strategy of OpenADR is based on modularity and interoperable platforms, thus reducing complexity and adapting to the evolution of the power grid.

Smart Grids provide a new distributed scenario in which resources and technology are decentralized and distributed along the grid with different stakeholders involved. All stakeholders should collaborate to implement intelligent strategies to guarantee a sustainable long-term vision in which the DSOs could purchase flexibility services in a market, thus assuring better performance and resilience of the power grid.

For Further Reading

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