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Contract principles between DSO and Aggregators and services lists from an Aggregator to a DSO

Deliverable D9.4

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Short Description

Deliverable 9.4 presents the three business cases of service from an aggregator to a DSO investigated through the three use cases of Nice Smart Valley – the French demo of InterFlex: islanding support, valorisation of a DSO owned storage and flexibility for local grid constraints. For each of these services, the products to be exchanged, valorisation and funding mechanisms as well as operation processes are described. Based on these investigations, contract principles are eventually proposed.

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EXECUTIVE SUMMARY

This deliverable presents the three business cases of services from an aggregator to a DSO investigated through the three use cases of Nice Smart Valley – the French demo of InterFlex:

- Islanding support
- Valorisation of a DSO owned storage by an aggregator
- Flexibility for local grid constraints

Each of these business cases are described through three parts, aiming at building the contract principles that are eventually proposed.

- The products: technical description of DSO expectations and of the services that have been identified to meet this expectation
- Valorisation of the service: how a DSO/aggregator can evaluate the value/price of the service
- Processes: what is the impact of the service on both parts processes

Islanding support service aims at maximizing the duration of the power supply to an islanded network after an unintentional disconnection from the main grid. In a context where an aggregator would operate a storage system on this islanded network, the DSO would have the possibility to buy a contribution in form of energy supply from this storage, while the DSO could operate a separate storage system to ensure the wave quality and the safety on the grid. As this service itself is far from generating enough value to enable an investment in a storage or for the DSO to pay for a service guarantee, this service would be an opportunistic service, on existing storage, without capacity reservation for the DSO. However, it requires an additional IT system needed to ensure the communication between all storage systems.

The valorisation of a DSO owned storage system aims at making storage investment affordable for a DSO for grid operation needs, in specific cases where there are no other choices, and with respect to the roles and obligation of a regulated party. Based on the two examples investigated in the French Demo – one DSO owned storage to island a portion of the distribution grid in case of an outage and another one to alleviate current constraints – a contract is developed to ensure a return on the DSO investment through a fixed part and a compensation from the DSO to the aggregator for the energy used when the DSO takes control over its assets.

Flexibility for local constraints has been addressed through a local mechanism based on a market approach with competition between aggregators. The presented products and valorisation mechanisms describe a general case, whereas the processes developed in the demo focuses on a DSO use case where the flexibility activation can be forecasted, that is to say flexibility enabling the alleviation of constraint occurring in case of investment postponement or work planning. The aim of the contract principles is to enable aggregators to have access to the local mechanism.

The contractual principles described do not claim to cover all use cases that may appear in the future. They were designed to be simple and pragmatic.

Contractual complexity should be consistent with the financial stakes. It should grow with the size of the market so as to allow in the short term a sustainable market development of it while ensuring the DSO the reliability of the products it contracts for the good operation of its network. As the size of the market grows, contractual rules should be enriched in order to deal more precisely with the issues left open at first.

This gradual escalation of contractual complexity is essential for the development of services for the benefit of the DSO.

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ACRONYM	Definition
ACR	Regional DSO Grid Control Agency (in its French acronym)
DER	Distributed Energy Resources
DSO	Distribution System Operator
DSR	Demand side response
GFU	Grid Forming Unit
GSU	Grid Supporting Unit
LV	Low Voltage
MV	Medium Voltage
SOC	State of Charge
TSO	Transmission System Operator

1. ISLANDING SUPPORT

1.1. Products

In Nice Smart Valley, two complementary islanding products have been identified but only the first one has been tested on the field. This section presents DSO's constraints (public service mission) and requirements (safety, stability and duration) that led to product definitions.

1.1.1. Grid constraints

One of Enedis' public service mission concerns high level of quality of supply.

This use case is related to resiliency of the electrical grid. In the present study, the French demo looked at solutions to improve the service quality beyond the actual situation on Lérins islands. An innovative solution has been designed to decrease the blackout duration for local customers in case of an incident on the submarine cable between Cannes and the first Lérins' island.

In Nice Smart Valley, the tested solution is based on an islanding system with no service interruption and no rotating generators.

Please note that today in case of a power outage on the submarine cables there is no way to energize the islands other than sending and connecting gensets.

1.1.2. DSO requirements

Safety

The participating assets (generation/storage/flexibility) must not decrease the security of goods and people (e.g. the capacity to detect a fault[1]).

Stability / Waveform quality

The islanding system must be stable at any moment. The assets on the field will not have a behaviour leading to:

- decrease the stability of the whole islanding system.
- a waveform quality which does not comply with Enedis' usual requirements (in normal configuration).

[1] Depending on how the islanding assets are controlled, they can participate to the fault detection. Enedis needs to perform an analysis to verify that the system does not decrease the level of safety for customers.

Islanding duration

A power outage on the submarine cable could lead to a 3-week period to fix it. During the demo, several studies have shown that a 3-week islanding would require a huge amount of energy (>100 MWh).

The temporary solution that Enedis would set up would be based on sending gensets onto the islands. The operation takes around one day to rent, send and connect them.

In the demo, Enedis wants to limit this customers' blackout duration by starting islanding operation as soon as the grid failure occurs and as long as possible before using the auxiliary generators.

Modulation of the power consumption/generation of the islanding assets

To maximize the islanding duration, the assets on the islands which actively participate to islanding must have a modulation capacity to increase or decrease their consumption/generation.

1.1.3. Products

Two types of services have been considered in Nice Smart Valley. The first one, which has been tested during demonstrations, deals with energy. Engie supplies to Enedis energy blocks based on a power fixed during 10 minutes which is defined by an algorithm within the islanding system.

Engie allows Enedis to maximize the theoretical maximal duration of islanding by limiting the blackout duration of local customers before the gensets are set up[2].

The second one is the capacity power supply enabling Enedis to provide a power higher than the capacity of its own storage. This service could be helpful for Enedis if its storage system's power is not sufficient to supply the maximum consumption of the islanding area at the instant of transition to islanding. This service has not been tested in the field.

1.2. Valorisation mechanism

This part explains how a DSO can assess the upper bound of the value created by such an islanding service provided by electric storage systems. Moreover, beyond this maximum assessment, a mechanism is proposed to compensate storage owners according to the service they provide, distinguishing GFU owners and GSU owners.

It is important to notice that Nice Smart Valley demo does not include local generation and demand side response to enhance the islanding operation.

1.2.1. Economical valorisation of islanding study

This section contains the results of a theoretical analysis relating to calculations of the upper bounds of the value of islanding of the Lérins Islands.

[2] The upper value of this service has been assessed and is detailed in section 1.2.1

Two distinct approaches have been performed in this section. The first one relies on the assessment of the value of an islanding system able to island for 3 weeks. It will give insight on the upper bound of the islanding value that a perfect islanding system would generate. The second one is based on the calculation of the value of a smaller islanding system able to island up to 3 days which is the maximum duration required to implement gensets for islanding sustainability. This part allowed the assessment of the upper bound of the islanding value of the system set up in Nice Smart Valley. The main difference between them relies on the costs considered. In the first case, the islanding system allows Enedis to avoid any gensets set up whereas in the second case, gensets are required as electric storage cannot last long enough. Hence the islanding system must last long enough to set up the gensets[3] which will supply customers as soon as the islanding with storage systems stops. Then, the second case assess the upper bound value of the electric storage set up permanently on the island.

The theoretical analysis involves the costs assessment for the community that would be generated by tearing off the cable between the city of Cannes and the Lérins islands (Sainte Marguerite Island).

Note that to be able to capture the maximum value, the service rendered by the system would have to be able to ensure a quality of energy for customers at least equivalent to the level of what the Enedis grid generates without islanding.

2.2.1.1 – Case 1: Upper bound of the value of a 21-day islanding system

Principle

In this specific case, where the islanding system is able to perform an islanding for the whole duration of the power outage, the considered costs are the following:

- The economic cost of failure to supply power to the customers based on the calculation of the undistributed energy;
- The cost of establishing and removing the solution with generator sets by Enedis (including crane handling, transport and the equipment needed for connection);
- The cost of operation of the temporary solution (hire, refueling).

The idea was therefore to estimate the sum of these 3 costs for various incident durations and various incident probabilities.

It should be noted that **the cost of the temporary solution is considered as the upper bound of the value that could capture any islanding system**.

We will now examine the input data that made these calculations possible.

Input data

Lérins Islands consumption data were obtained by placing recorders on four of Lérins Islands' five MV/LV substations. Since the fifth substation was not instrumented, its load was estimated. Likewise, the active losses in the cables were estimated.

[3] Practically Enedis' decision to send the generators or not relies on several parameters other than economic.

Figure 1 shows the estimated load curve of the islands corresponding to the sum of the measurements and the estimate for the non-instrumented MV/LV substation. It can be seen that the consumption peaks in this period are reached in September-October 2018. This can be explained by the fact that it is the end of the tourist season generating greater loads due to the operation of restaurants. Moreover, it can be expected that consumption will be even higher in the months from June to August, but Enedis has no recording for this period, so the analysis will be confined to the period shown hereafter.

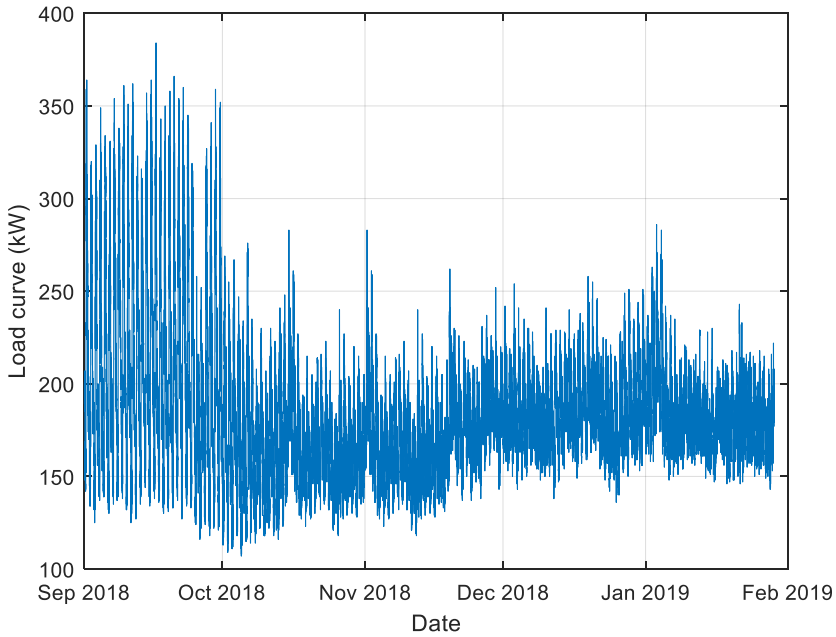

Figure 1 – Estimated Lérins Islands load curve without PV production and without storage from 01/09/18 to 26/01/19.

Assumptions

Durations

We will consider that the duration between the incident and effective repair of the cable is 21 days. The analysis was performed for two cases corresponding to different power outage durations for the island customers:

1. A 1.5 days blackout in case of very favourable weather conditions. It is considered that this is the minimum duration between the incident and actual take-over by the five gensets brought to Lérins Islands under ideal conditions;
2. A 3 days blackout in case of extremely unfavourable weather conditions making it impossible for Enedis to rapidly send and start up the generator sets on the islands.

This duration impacts the number of days the genset would have to operate, which would be 21-1.5 = 19.5 days or 21-3 = 18 days, depending on the case.

Gensets

The 5 generator sets sent to the spot are sized to supply the maximum load of each MV/LV substation of the Lérins Islands. It is considered that the gensets operate as soon as they are connected, and until cable repair. In this analysis, the costs related to the gensets come from Enedis internal contracts.

Probabilization and discount rate

The presented results are probabilized and discounted. A bibliographic study was conducted to estimate the probability of occurrence of tearing off an undersea cable. The values found in the literature vary from approximately **0.1 incident/year to 0.01 incident/year**. The results in the following section are presented taking into account these two probabilities separately. **The discount rate is set at 0.045 over a period of 10 years**. This period was chosen because it is considered that the battery has a lifetime equal to 10 years.

The assumptions have been determined, and we will now examine the results of the analysis for two cases: with 1.5 days and with 3 days of local blackout duration.

Valuation of the non-quality generated by a 3-week incident

In this part, we will value the cost for the community of cable tearing engendering a total repair time of 21 days. As explained earlier, **this cost is the upper bound for the value of an islanding system** given that this is the solution implemented by Enedis in the event of damage.

Note that, to date, no grid reinforcement has proved technically and economically more efficient for the community than implementation of the remedial solution.

Case of 1.5-day customer power cut

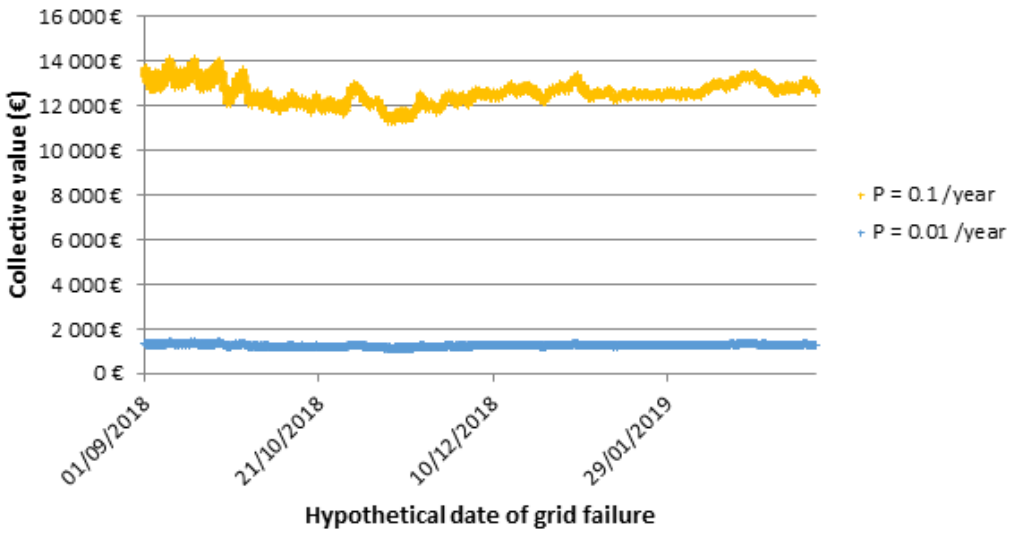

Figure 2 below presents the results concerning analysis of the collective cost of cable tearing between Cannes and Sainte Marguerite Island, depending on the time of the start of the

incident and for a customer power cut lasting 1.5 days. The two scatter diagrams show the cases for incident probabilities of P = 0.1/year and P = 0.01/year. The collective costs below take into account the valuation of the undistributed electricity and opex for the generator sets. Each point of the graphic represents the collective value of incidents appearing at the considered date for a 1.5 days of blackout duration.

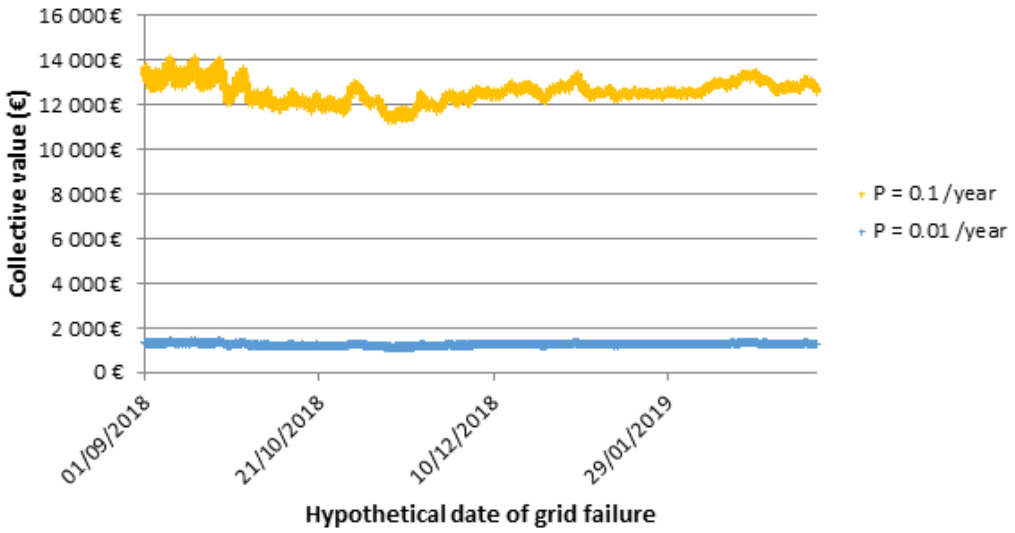

Figure 2 - Collective cost of tearing of the undersea cable leading to a customer power cut of 1.5 days depending on the time of the incident

In the case of a period of 1.5 days during which customers are not supplied with power, it can be seen that the collective cost of this incident may vary from €1,129/year (if P = 0.01/year) to €14,134/year (if P = 0.1/year and if the fault occurs at the autumn consumption peak observed for the year 2018).

Case of 3-day customer power cut

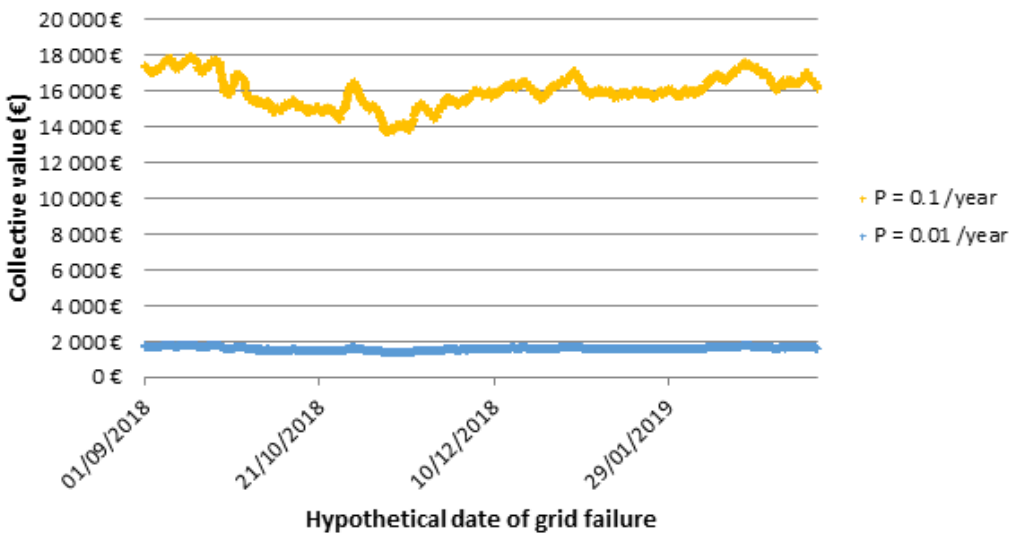

Figure 3 below shows the results taking into account the valuation of a 3 day customer power cut. Each point of the graphic represents the collective value of incidents appearing at a considered date for 3 days of blackout duration.

Note that the incident still lasts for 21 days which means that the operational costs of the gensets are reduced whereas the undistributed energy has increased.

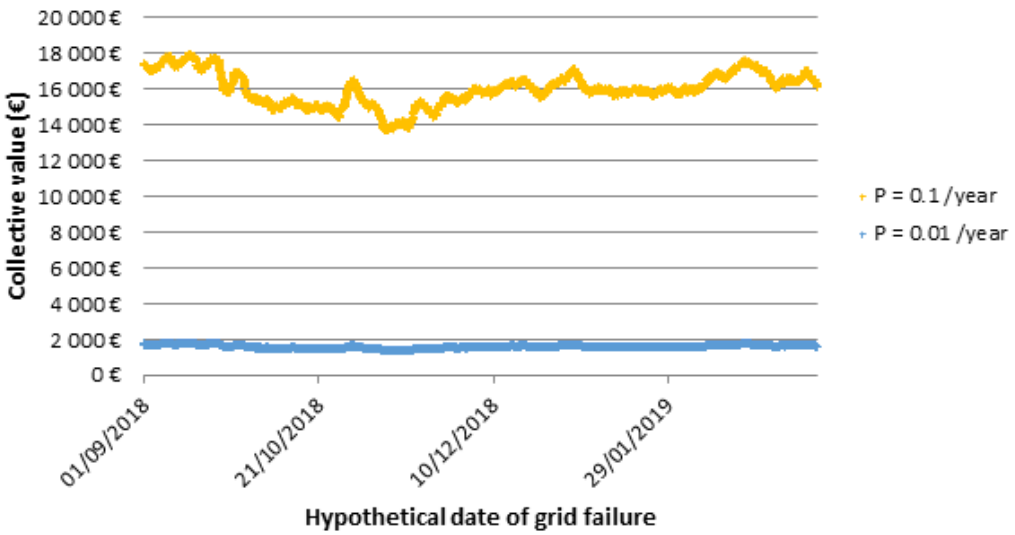

Figure 3 - Collective cost of tearing of the undersea cable leading to a customer power cut of 3 days depending on the time of the incident

The results indicate that a system capable of starting 3 weeks of islanding, without a power cut, would make it possible to capture at least €1,367/year (for 0.01 incident/year) and at most €17,943/year (for 0.1 incident/year) for the consumption values observed over the months studied.

We have defined the upper bound of the value for a 3 weeks' incident on the Lérins Islands. We will now briefly consider the total battery capacity which would make it possible to capture a maximum of value.

Energy necessary to capture a maximum of value

In this section, we are concerned exclusively with the theoretically most energy-hungry islanding over 3 weeks. This was identified by calculating the maximum energy consumed by the islands during three weeks. It can be deduced from an analysis that at the time of starting islanding, an energy of about 110 MWh would be needed for it to last 3 weeks.

For sake of comparison, the total capacity of the storage systems that will be put in place in Nice Smart Valley is 890 kWh. So it would be necessary to have a system with more than 120 times more capacity to be able to have islanding lasting for 3 weeks, in the most unfavourable case noted over the few months of data.

Note: a Section in D9.3 is dedicated to a complete study of the combinations (batteries, photovoltaic panels) making it possible to have different islanding durations.

With current technology, it is hard to imagine that a system could one day be capable of islanding the Lérins Islands for three weeks without local production and a consumption control system. A 110 MWh system would make it possible to capture a maximum of value, but smaller systems could also capture a part of the value. This is the subject of the following part, which contains a value analysis of an islanding system of a smaller size.

2.2.1.2 – Case 2: Upper bound of the value of a 3-day incident for the DSO

Here we have considered the upper bound of the value of a system capable of islanding for a limited duration, inferior to the time to repair the undersea cable. It should be noted that, in the cases described below, **sending generator sets to the islands could not be avoided, given that the system would be unable to prevent a long power cut for customers**. This aspect has a significant impact to the extent that only part of the upper bound seen earlier, and taking into account a 3 day duration, could be captured.

Principle

In this case, the gensets will be sent onto the islands to supply the customers when the islanding system will stop. It means that the avoided costs to be considered for the system is only the economic cost of failure to supply power to the customers based on the calculation of the undistributed energy.

The idea was therefore to estimate this cost for various failure durations and various failure probabilities.

It should be noted that only **the part of the avoided cost of the local blackout is considered as the upper bound of the value that could capture the considered islanding system**.

Input data

As for the previous section, the consumption of the two islands was used to assess the undistributed energy (see the previous section for more details).

Assumptions

<u>Durations</u>

In this study, only the undistributed energy is assessed as we consider that the islanding system would only be able to island for the duration Enedis needs to set up gensets. The considered durations vary from 0 to 3 days.

Note that only the case of a 3-day blackout duration is assessed in this study.

<u>Probabilization and discount rate</u>

The same assumptions as in the previous study have been used (see the previous section for more details).

Valuation

Figure 44 shows the cost over time of the temporary solution for an incident probability of 0.1/year and if one were to consider a 3 days power cut for customers. Since the value rises faster in the first three days (valuation of undistributed energy exceeds the valuation of gensets), it would be more useful to start islanding at that time, especially since the generator sets would not yet be on the site, generating non-quality that Enedis could not limit otherwise.

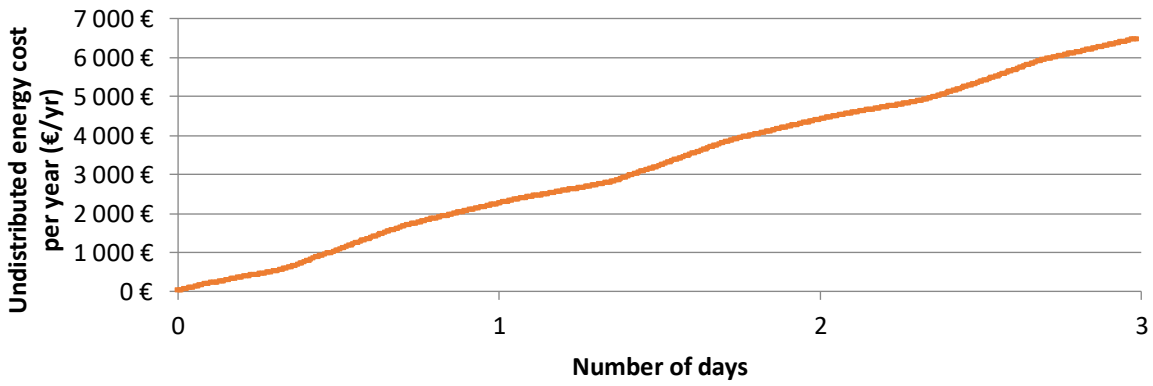

Figure 4 – Upper bound of the cost in undistributed energy versus time over the first three days of the power cut for customers (the most energy-hungry case for the months of data)

Based on the valuation of the undistributed energy, this graph shows that in the most constraining case for Enedis, **for an incident probability of 0.1/year**[4] and in case of islanding on a most energy-hungry day over the period in question described above, the upper bound of the value for a one-day islanding system is €2,259/year. For information's sake, without generation units and without a consumption control system, this islanding would require 5.3 MWh of batteries in all to be able to start at any time islanding for a duration of one day.

2.2.1.3 – Valuation of the system tested in Nice Smart Valley

We now consider calculation of the upper bound of a defined system. The upper bound of the value corresponds to the energy that can be used for islanding multiplied by the value of the energy. In the case of the system on the Lérins Islands, the upper bound of the value of this system is €410/year for a maximum islanding duration of 5h 40min. over the period considered above.

2.2.1.4 – Conclusions

This low value can be explained by the fact that the probability of occurrence of the incident is relatively low. Moreover, the equipment installed on the Lérins Islands has not been sized with a view to maintaining islanding for a very long period of time. Also, the initial project design included a local solar PV production which was was unable to be established for administrative reasons. As a consequence, the Lérins Islands system can only capture a small part of the value of the undistributed energy.

To go further:

One could ask what contribution a local flexibility system would generate, for example, by imagining a demand side management system. A distinction can be made between two cases: a reduction in the maximum power demand and load shedding of non-critical uses having a low utilization value. This point has not been dealt with in Nice Smart Valley but could offer

[4] To obtain the same results for an incident probability of 0.01/year, the results shown in €/year should be divided by a factor of 10.

prospects that it would be worthwhile examining in the future. That would reflect different electricity utilization values and could avoid unnecessary backup costs by sizing the islanding system considering the load shedding of part of the two islands' consumption.

1.2.2. Funding system

The aggregator's Grid Supporting Unit (GSU) might support the DSO's Grid Forming Unit (GFU) in case of incident, so the DSO will take control of the GSU to extend islanding. The aggregator will then be paid according to:

- Fixed cost defined by the transfer of the control from aggregator to DSO;
- Variable cost defined by the energy used. At the end of the event, the DSO will return the asset at a lower SOC, and the aggregator will have to charge the battery in exchange for a fee.

1.3. Processes

The Islanding use case tested in Nice Smart Valley is simple and pragmatic: The technical installation has been designed so that the GFU is sufficient to cover the needs at all times (no behind the meter load management at restart). Therefore, the GSU provides only energy and no power beyond GFU nominal capacity. Moreover, in the absence of local generation, the process only manages emptying of available storage and not of any refills. In the use case tested in Nice Smart Valley, **the use of GSU storage is opportunistic**: the DSO does not provide any compensation for the availability of the GSU capacity. Therefore, there is no commitment of it in terms of availability. The operational process has been designed accordingly.

In the future, we could consider a more complex mechanism in which islanding management would combine consumption flexibilities and generation. The GSU could also provide capacity support beyond just energy support. In this case, the process would be modified because the GFU would manage its storage and that of the GSU differently to maintain as long as possible all sources of capacity and thus ensure a longer islanding.

1.3.1. Technical description of the processes

Process tested in the field

Two storage systems have been installed for this use case:

- One Grid Forming Unit (GFU) 250 kW / 620 kWh operated and monitored by Enedis for islanding purpose.
- One Grid Supporting Unit (GSU) 33 kW / 274 kWh operated and monitored by Engie for self-consumption and islanding purpose[5].

[5] As the state authority refused the installation of local PV generation, the self-consumption is simulated based on real measurement data: the storage is managed as if it was installed behind the meter on La Poste premises in CARROS where PV generation is installed and as if it was to be self-consumed.

In normal operation, Enedis' asset will only be used for islanding purpose. In other words, its state of charge will be kept high to maximize the theoretical duration of an islanding if a power outage occurred on the submarine cable.

In normal operation, Engie will operate its asset to monetize it on several value pockets (value stacking). Moreover there is no commitment request on Enedis side for this service, therefore, there is no minimum state of charge guaranteed by Engie in case of islanding mode.

The figure 5 below details the process from Enedis' order to start islanding to an islanding end. It always starts with an Enedis' signal requiring an islanding. The GFU checks its internal indicators to know whether an islanding is possible. If they are good, an islanding can be started.

The GFU then automatically starts to locally balance local consumption and generation to minimize the current in the submarine cable between Cannes and Sainte Marguerite[6]. Once the balance is obtained, the GFU opens the islanding breaker to isolate the islands from the main grid (i.e. islanding is started).

The GFU now controls the balance between consumption and generation and acts as a full system operator (equivalent to a TSO). As long as the GFU's state of charge exceeds its SoC threshold 2, the islanding can go on. If its SoC decreases below the SoC threshold 1, the GFU can ask the GSU to modify its setpoint to offer energy which would maximize the islanding duration. The GSU replies depending on its energy available for this purpose. When the energy available of GFU's battery becomes too low, islanding is stopped by a reconnection to the main grid (in case the upstream grid is available) or a local blackout occurs.

Note that:

- *the only manual steps in this process are the order to start and the order to reconnect to the main grid at the end of the islanding.*
- *at any moment during the islanding, if an internal indicator of the GFU exceeds its thresholds or if GFU's SoC is too low, the islanding stops with a local blackout for customers.*

With:

- SoC thres 1: represents the threshold from which the GFU asks energy to the GSU.
- SoC thres 2: represents the minimum acceptable SoC for the GFU's battery, leading to the end of the islanding.

[6] Note that this last step is a prerequisite for seamless islanding and has been defined in the project for the technical challenge and to limit the impact of islanding on local customers. In the real case of a power outage on the submarine cable between Cannes and Sainte Marguerite, there would be at least a short blackout before starting islanding.

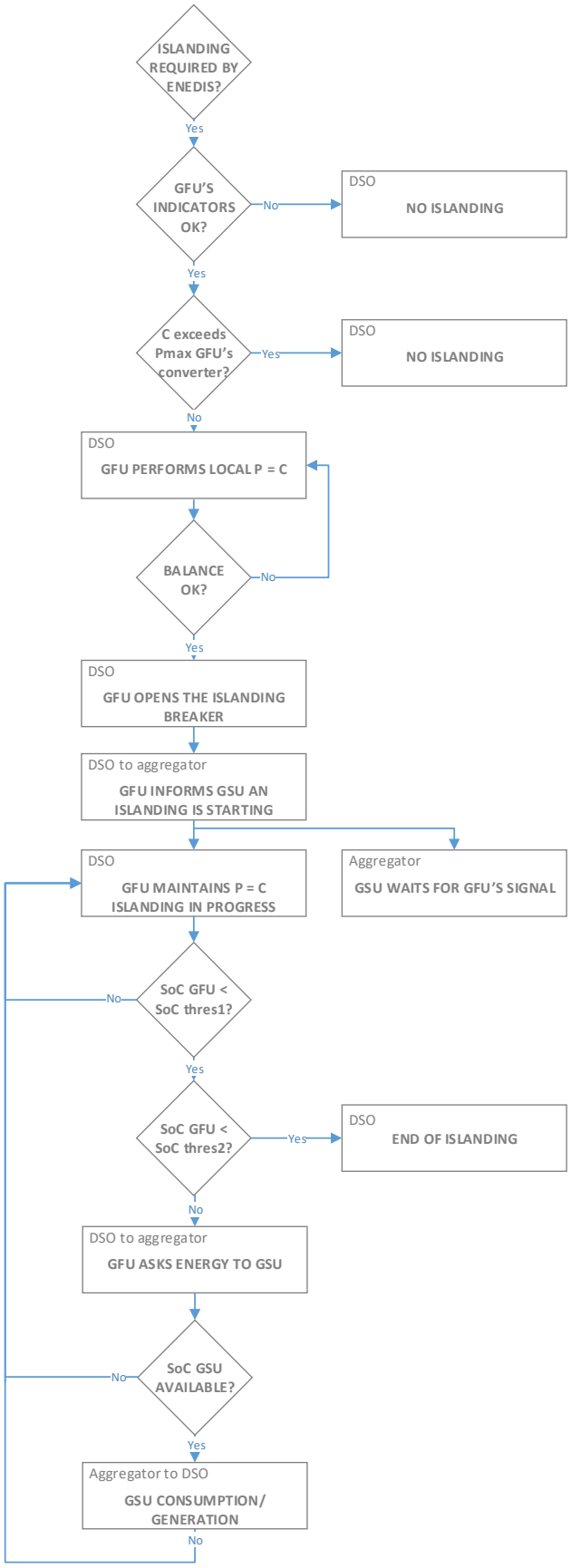

Figure 5 – Schematic of the process of an islanding sequence until the system cannot supply the consumption of the local customers

Proposal of process with the addition of DERs, load shedding system and a forecast tool

As explained above, the tested process considered that the GFU installation has been designed to cover the needs at all times. Practically, we can imagine that the DSO does not design its asset depending on the overall maximum consumption/generation of the islandable area.

The idea is that a potential flexibility system could be used to:

- decrease the power supplied by the GFU in case the islanding cannot be started or if the net consumption exceeds the power capacity of the GFU;
- limit the energy consumed/generated by the islands.

The figure below details one of the possible processes that could be set up to maximize the islanding duration with an undersized GFU. The two main differences between this process and the one tested in the field are the following:

- A forecast tool assesses the local consumption & generation to feed the controller of the islanding system. These informations could allow:
    - the GFU to assess the local consumption at the expected islanding time. If the forecast exceeds the maximum power of the GFU, it can require load shedding to decrease the consumption allowing the islanding to start.
    - the design of a function that dynamically changes the upper and lower SoC thresholds 1[7] of the GFU that start the flexibility process. The idea is to optimize these thresholds to maximize the islanding duration.
- As soon as GFU's SoC exceeds its thresholds 1, the system is able to ask for flexibility to aggregators (the GSU is here considered as a flexibility).

The **Erreur ! Source du renvoi introuvable.**6 below describes a process that could have been tested if all of the functions described above were instrumented.

Note that in this process, the islanding would be performed with no local blackout. It would require equipment that would not be needed if very shorts blackouts were permitted before and after the islanding.

[7] Here the GFU's upper and lower thresholds are dynamically calculated by an algorithm which defines the optimal thresholds to start the flexibility function maximizing the islanding duration.

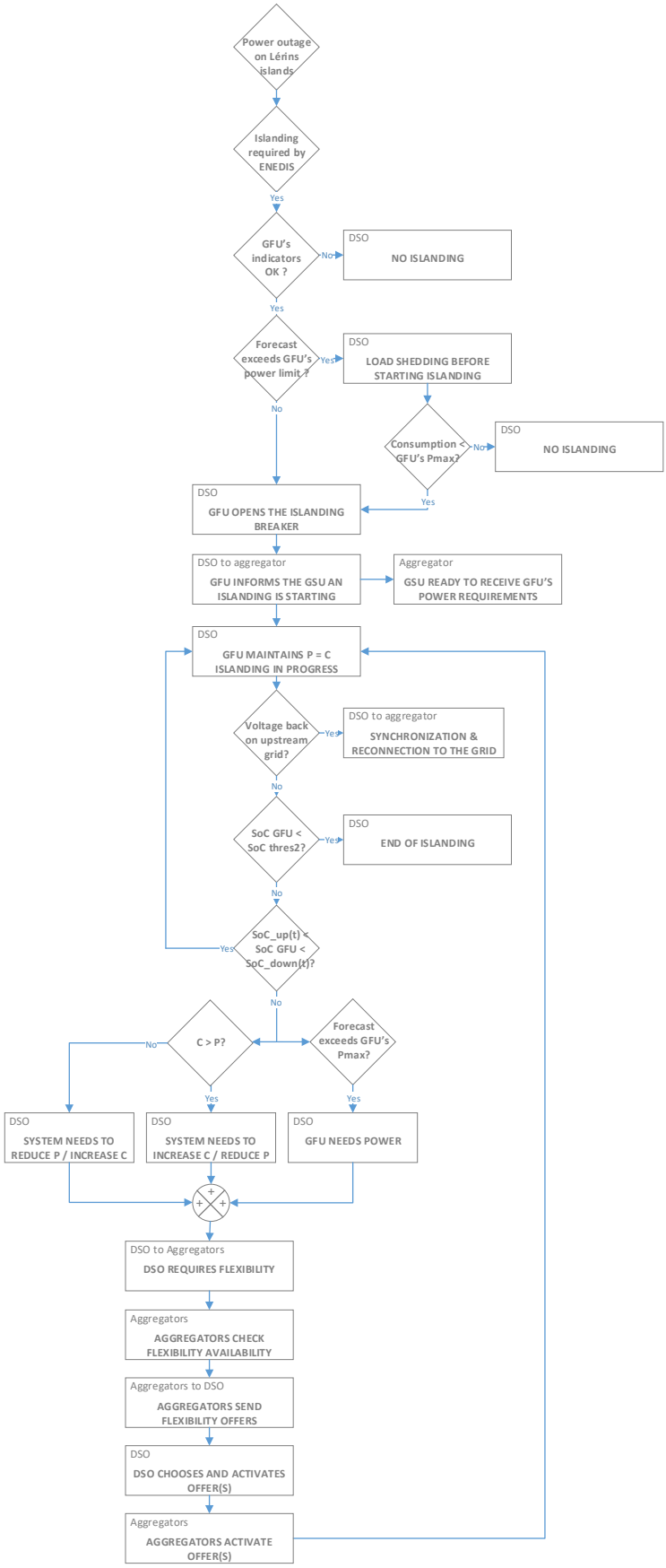

Figure 6 – Proposal of process for islanding with DERs, a load shedding system and a forecast tool

It shall be noted that the process presented above is relatively complex but does not include all possible cases. Indeed, some other investigations are required to:

- define the detailed process of flexibility activation (optimal time step calculation by the algorithm, etc.);
- assess whether a double time-step process should be used by the DSO to require long blocks of energy at D-1 (via forecasts) and shorter blocks in intraday;
- assess whether the flexibility market would be a good way to operate in real time the islanding considering in particular its liquidity.

1.3.2. Interaction of islanding support service with other processes of an aggregator

During an islanding the flexibility (either from a battery or from electric appliances) is no longer connected to the main grid. This impacts the aggregator's portfolio if the flexibility which is temporarily islanded was committed to other value pockets. In this case, the aggregator may have to activate another flexibility to avoid this loss[8].

In addition, outside the islanding period, the aggregator processes can be impacted if the aggregator has commis to guaranteeing available energy in the storage for islanding duration increase purpose. In this case, the aggregator needs to manage the storage by ensuring that a base charge is always available to ensure the guaranteed service to the distribution system operator. This operation could influence the sizing of the storage capacity. Indeed, the latter has to correspond to the needs of the storage operator for his functions beyond the islanding (e.g. self-consumption optimization, TSO ancillary services, etc.).

If the aggregator has no commitment to the distribution system operator, which is the case in the project as mentioned above (see part 1.3), there is no impact on its other processes when it is not in a period of islanding.

In conclusion, the impact on the aggregator's processes depends on the nature of the commitment requested from it by the distribution network operator. In the Nice Smart Valley Demo, the only impact to be managed is the aggregators' commitments when its flexibility portfolio is disconnected from the main grid.

1.3.3. Service check

The settlement is performed by using GSU's load curve into the smart meters. In Nice Smart Valley, during islanding, GSU's power setpoint is zero as long as the GFU does not ask energy. Thus all the energy generated or consumed by the storage system is asked by the GFU.

[8] Note that this situation is already included in the regulation and considered by aggregators for the flexibility portfolio management: every distribution network connection contract specifies that interruptions of supply cannot be totally avoided. The number and/or the cumulative duration of interruptions under which the customer is not compensated depends on the voltage level and the type of customer (Consumer or producer). Additional contracts with extra grid tariffs can be set to ensure a continuous supply. This means that the consequence of a disconnection to the main grid, as soon as the number of interruption stays beyond the limit of what the regulation (or additional contracts) sets is today undertaken by aggregators.

A simple energy analysis of GSU's load curve based on islanding start and islanding end instants is sufficient to assess the realized contribution. This analysis is sent to Engie at W+1.

Enedis will also compare GSU's load curve to GFU's setpoints curve to verify that Engie's storage does not consume or generate beyond its setpoints.

1.3.4. Impact on balance responsible parties and other market players

The impacts are the consequence of the islanding and are not the consequence of the service supply to the DSO.

The impact is very small on Balance responsible parties and is rather positive with the current regulation: Currently, during islanding mode, electricity is supplied from diesel gensets owned and operated by the DSO. The supplier is paid by the customer for this electricity and the balance responsible party (BRP) is paid by the TSO as its balancing perimeter is long. The unbalance price is lower than the day ahead market price. However, the supplier do not pay the DSO for the electricity injected during the islanding mode. Those costs are ultimately supported by all French consumers through the distribution network tariff. As the considered electricity volumes are small, the impact at the end of the day is small.

The impact on aggregators is more important and must be managed: during an islanding mode, the storage is no more available for other services supply for instance ancillary services. Therefore, the aggregator must consider this in its portfolio management and either alert its flexibility customer for this failure or mobilize other flexible assets.

1.4. Contract Principles

The contracts principles are the following:

GSU pre-contracting

Enedis needs to contract with the storage operators which agrees to let Enedis use their storage as GSU. The contract defines the price for the service according to the following principle.

Description of the service

- The service consists in an ability of the GSU to inject or withdraw on demand a quantity of energy at a power within an interval [-P; +P]
- Orders are made at an hourly time step. The GSU pilot program has a maximum of X cycles per day.
- There is no commitment from the aggregator relative to the availability of the electricity storage system made available to Enedis. Enedis remunerates the service only when it is used.

Payment

A first payment is one shot when the DSO requires the Aggregator to let the DSO use its storage as GSU. This payment is covering the cost of the control chain required to operate the GSU during the islanding. If the DSO is using the Aggregator control chain, then there is only a cost for connecting the DSO IT with the Aggregator IT. This link can be used for all

the storage owned by the Aggregator that could be used as GSU by the DSO. Hence this IT cost would only be paid once, for the first GSU project.

Note that this link could be used for GSU management and other assets management such as local generation and demand response.

Beyond this fixed cost, a payment is made per use. It has two terms:

- A term that is proportional to the duration in hours of use of the battery. This term represents the fixed cost for the aggregator to transfer the control of its battery (mainly maintenance costs and amortization).
- A term that values the electricity consumed by the distributor during the islanding period. In the absence of PV generation, this quantity is equal to the sum of the difference in energy stored between the beginning of the islanding and the end of the islanding and the consumption of auxiliaries during the islanding period.

Responsibility

The distribution system operator is responsible for the proper operation of the battery during island periods. In addition, the distribution system operator is liable for damage to goods and persons that may be caused directly or indirectly by the battery during the islanding period.

The control chain is implemented by the Distribution System Operator. It is responsible for its proper functioning and availability.

Penalties

Penalties shall be applied if the DSO does not respect the operational constraints: maximum number of cycles per day and minimum energy to be left in the storage.

1.5. Conclusion

The analyses carried out within the UC1 framework show that the value of an islanding service provided by electricity storage is rather low. In fact, a storage of electricity installed in a given area cannot avoid the costs of deploying generators when these are considered necessary by the DSO because of the duration of repair works. For this, the area should be self-sufficient thanks to local generation and to consumption curtailments. Such conditions have not been met to date.

Therefore, under the current economic conditions, it is not possible to make an electricity storage systemprofitable based on this only service. It is required to draw value from the storage from other counterparts. This is the purpose of the UC2 study.

To go further, the next steps would be to:

- study how to exploit an islanding involving several GSUs, local generation (renewable or not) and the curtailment of some non-critical consumption of electricity in order to maintain the supply of all critical uses on the islanded area for the duration required to avoid the use of gensets
- study the acceptability of such solutions and the contracts to be concluded with consumers in the area
- study the sizing rules for the GFU storage

2. VALORISATION OF A DSO OWNED STORAGE BY AN AGGREGATOR

2.1. Products

2.1.1. Context of the business case

The project aimed at finding ways to maximize the profitability of a DSO owned storage[9] by contracting a service with an aggregator able to use the storage when it is not needed by the DSO. Two use cases in which a DSO owned storage would be relevant were identified:

- Grid resilience improvement: in isolated areas without rescuing solutions from other feeders ("antennas"), a storage system can be a back-up solution. This is typically the case for the GFU of Lérins islands described in part 1**Erreur ! Source du renvoi introuvable.**[10]
- Constraint alleviation: in areas without a local flexibility mechanism, storage systems can be a temporary solution for the DSO. This is the scenario tested on the 33KW storage system installed in Carros.

In both use cases, the DSO needs the storage availability to be guaranteed when the incident/constraint occurs. However, grid constraints can be forecasted whereas MV outage cannot, leading to two slightly different processes and products.

In this use case, 2 cases are distinguished:

- **Carros case**: the Aggregator is warned the day ahead that the DSO will need to use the storage. Then, the Aggregator will ensure that the state of charge is high enough, accordingly to the contract principles.
- **Sainte Marguerite island case**: the aggregator can't be warned and will ensure that the SOC is always above the minimum level requested by Enedis.

2.1.2. Products

In this use case, the DSO draws benefit from its storage assets with an aggregator. The valorisation method is dependent on risk sharing between the DSO and the aggregator:

- If the DSO wishes to take advantage of market opportunities, it retains the price risk. In this case, the aggregator optimizes the use of the DSO asset in order to extract the maximum value from the markets. These revenues, from the market, are fully paid to the DSO by the aggregator. For its part, the DSO pays a service fee to the aggregator including a fixed part and possibly a variable part encouraging the aggregator to maximize the battery management performance considering the real

[9] It should be noted that as an innovation project aiming at testing technical and business solution launched in 2017, the presented solution might not take latest regulation developments into account. The model developed here aims at lightening potential developments but does not necessarily reflect the project partner's official positions.

[10] See also deliverable D9.3 on lessons learnt for detailed explanation of this use case

availability of the battery. This variable part may take the form of a premium of +/- X% of the amount of the fixed portion or a profit-sharing in case of overperformance.

- if the DSO wishes to secure the profitability of its investment, it may wish to minimize its exposure to the risk of price fluctuations and want a fixed income from the aggregator. In this case, beyond the operational characteristics (power, available energy, maximum number of cycles per day and per year, etc.) the aggregator must estimate the potential income of this asset, to commit to a fixed remuneration. For this, the aggregator needs information concerning the periods during which storage can be valued. The more information the aggregator gets from the DSO the more the aggregator can reduce the risk premium linked to uncertainties in its pricing. The necessary information is for example: the number of days and hours during which the storage cannot be used by the aggregator and the periods of the year during which the storage is likely to be used by Enedis.

In Nice Smart Valley, we are simulating a use case where Enedis wants a guaranteed income from Engie for the storage made available. Enedis thus describes the availability of its storage.

In the context of a remuneration guaranteed to the DSO by the aggregator, the choice of the aggregator in terms of valorisation of the storage is constrained only by technical aspects:

- Number of cycles per day and year
- Reactivity of the command control chain
- Storage efficiency
- Quantity of storable energy in relation to converter power and connection

The aggregator monetizes the asset on all the available value pockets in France as listed in Deliverables D9.2 and within the limit of the cumulation of values.

In the particular case of Nice Smart Valley, the control-command chain does not allow the aggregator to control the DSO battery at time-steps inferior to one hour. As a result, Enedis storage can be used by Engie on the day-ahead and intraday energy markets, on the capacity market and as storage for prosumers connected behind the same MV/LV substation and part of a collective self-consumption scheme. Indeed, the energy community can exchange electricity with a cheaper distribution tariff.

Engie remunerates Enedis only by a fixed share.

- For CARROS case, Engie commits to make Enedisits fully loaded[11] storage available to Enedis if requested in day-ahead,
- For Sainte Marguerite Island case, Engie commits to never empty the SOC beyond contracted value. Enedis returns it to Engie at a new state of charge and Engie will charge Enedis for the difference of state of charge between the beginning and the end of the operations managed by Enedis.

[11] The load level is fixed by contract. In the case where the constraints may be due to local overproduction, the DSO may prefer a lower initial load level. He indicates it in the contract.

As for Enedis, the DSO ensures the maintenance of the storage and its availability accordingly to the contractual commitments. Storage availability covers hours of operation, power, amount of storable energy, and efficiency.

2.2. Valorisation mechanism (Engie – Confidential)

In this business case, Engie is compensating Enedis for the storage availability. To do so, Engie needs to assess the value that can be extracted from the storage during the contracted period of time. Then Engie assesses the value according to the internal risk management rules, includes a margin and proposes the value to Enedis.

2.3. Processes

Enedis has installed a 33 KW battery in the city of Carros for several needs:

- For Enedis to relieve local grid constraints and support local flexibility
- For Engie to monetize the battery on competitive markets

Enedis is in charge of monitoring the asset, therefore the battery will be activated either on aggregator's demand to offer ancillary services to the DSO or to relieve local grid constraints.

2 templates have been designed to operate the use case, as the local grid constraints are predictable.

In normal operation, the aggregator will operate the asset and value it as described above. If a constraint is predicted, the aggregator will be informed within 14 days and at least 1 day ahead of the possible unavailability of the battery on a specific day. One day ahead the presumption of the constraint grid, the DSO will or will not confirm the availability of the asset:

- Case of confirmed constraints: the DSO will relieve the grid using the battery. Therefore, the DSO will require a specify state of charge to catch up the constraint, the aggregator will then charge the battery according to DSO needs. On D-day, the DSO will check the state of charge, the asset will not be returned to its initial state of charge. The aggregator will charge a fee for the restock supplied (see §1.4).
- Case of unconfirmed constraints: the aggregator will have the asset at his disposal for market monetization use.

The process scheme is shown in figure 7.

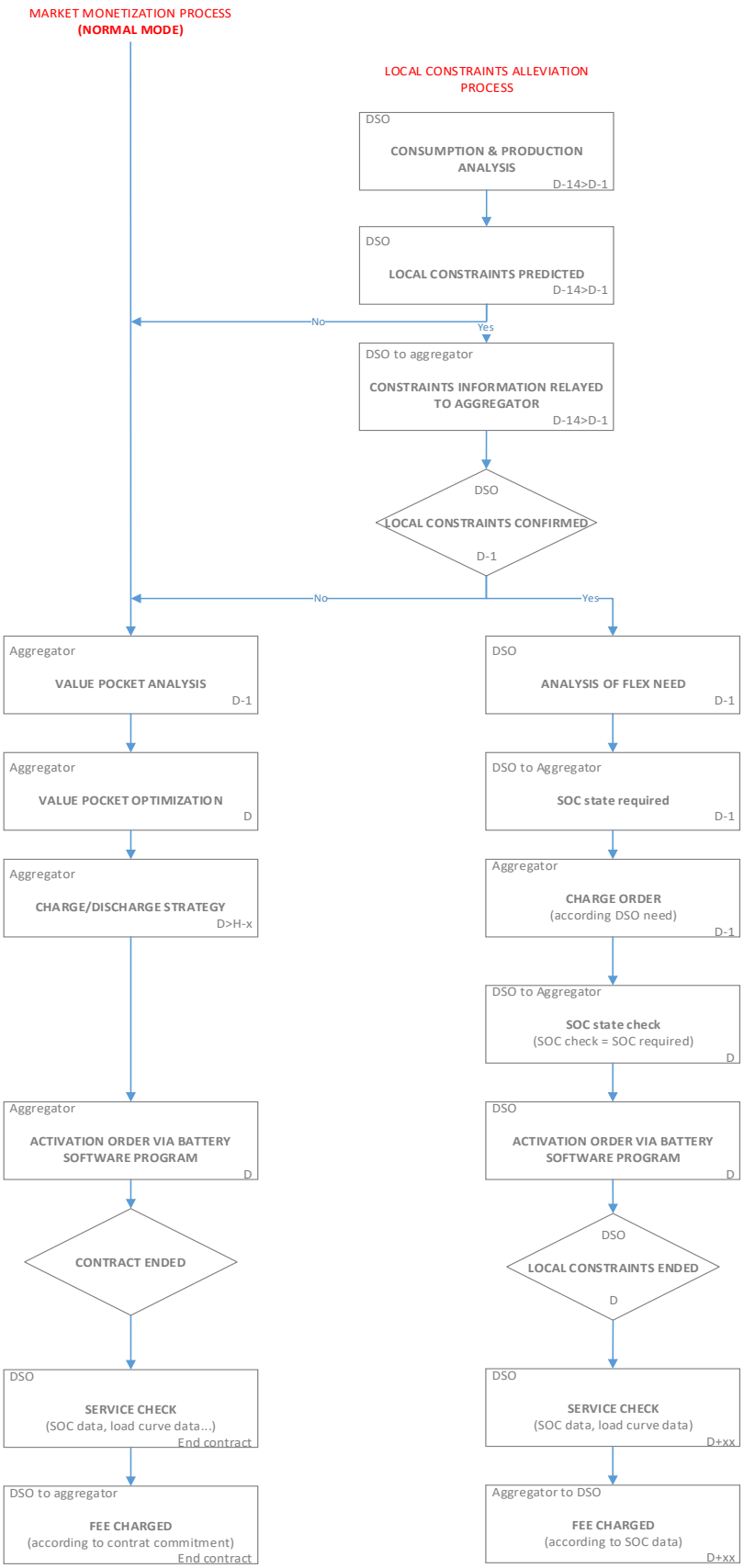

Figure 7 - Scheme of the market monetization process until a local constraint is predicted (Carros use case)

On the Saint Marguerite island, a 250 kW asset has been installed to improve grid resilience in case of unforeseen interruptions with no back up to maintain customer service (islanding case described in part 1). In that context, the battery will be used:

- to guarantee electric service over incident grid occurrence by DSO
- to monetize value on market by aggregator

In order to ensure the supply of energy and as the incidents aren't predictable, it implies that a minimum SOC will always be available at any time to insure the grid resilience. The minimum calibration would be defined according to grid needs.

In term of processes, the aggregator operates the battery as long as there is no incident. As soon as a breakdown is observed on the grid, the DSO takes the control back on the asset checking the SOC state (SOC = minimum calibration contractualized) and activating the battery to relieve the grid constraint (process described in part 1). At the end of the event, the DSO returns the battery to aggregator, which would have to charge the battery in exchange for a fee.

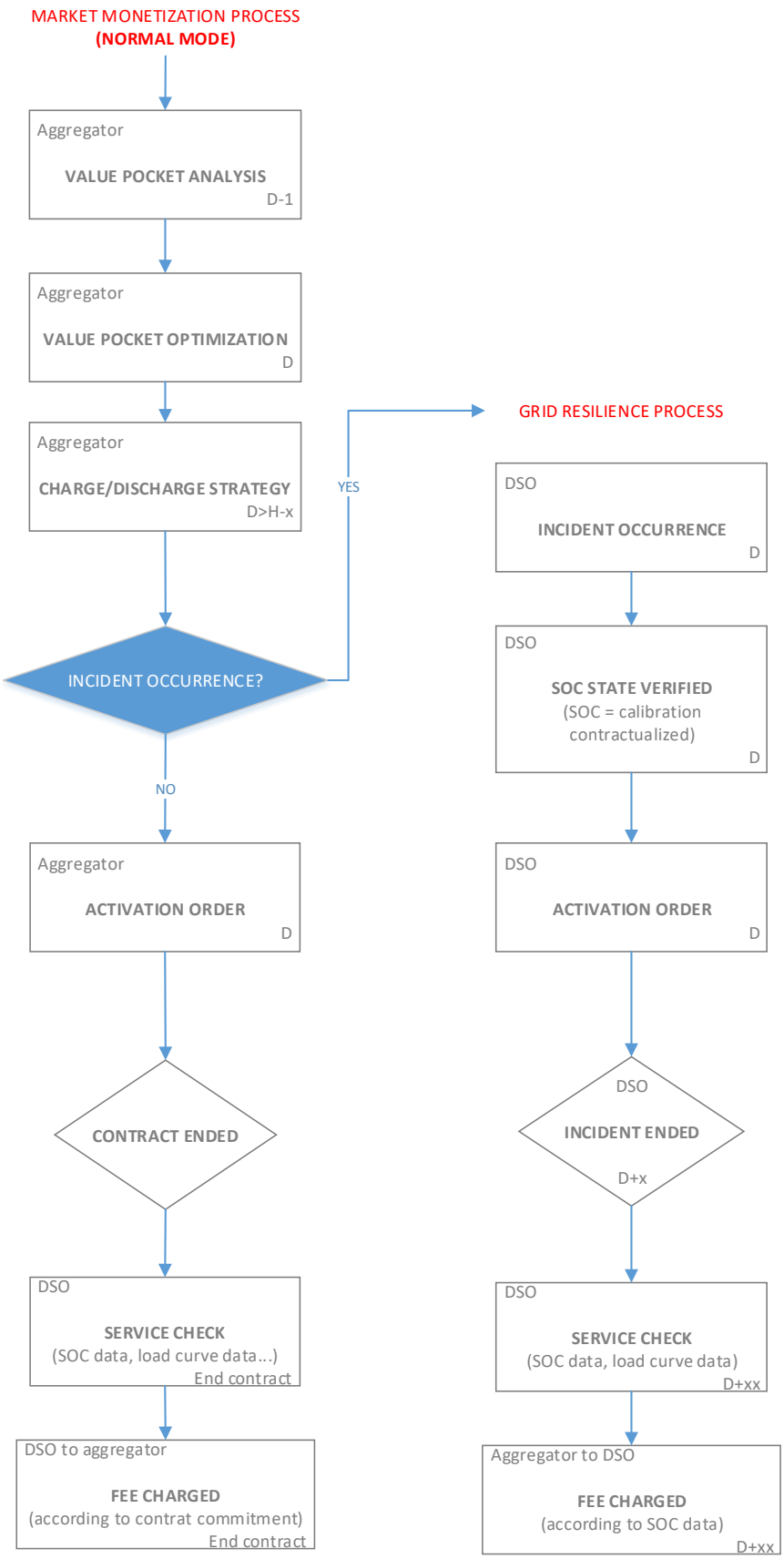

Figure 8 - Scheme of the market monetization process until a grid incident occurs (Ste Marguerite use case)

2.3.1. Technical solution

The architecture of the electric and communication solution has been designed according to the different use case needs.

The battery is connected to the grid through a transmission station with a communicating two-way electric meter in order to follow the energy injection or withdrawal.

To enable more agility in the battery use a software program has been developed to remotely control the asset using 3G network.

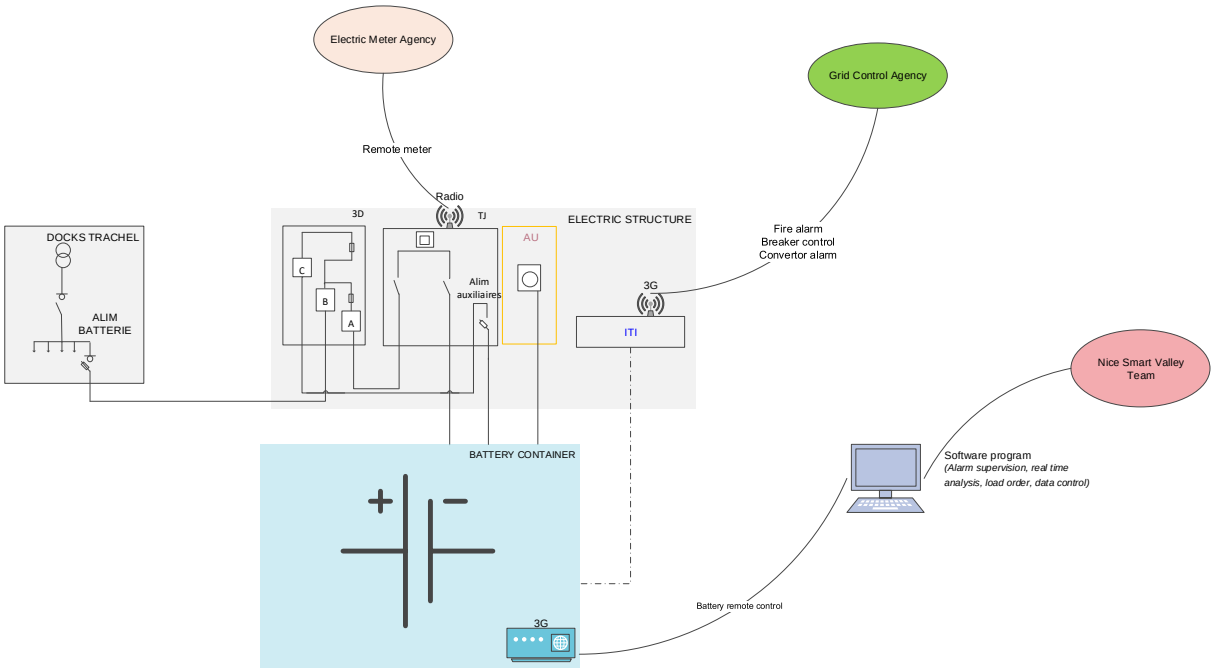

Figure 9 - Scheme of the technical solution, electric connection and communication system

The software program enables:

- Charge/discharge activation according to load curve
- Alarm and warning observation
- Data control (SOC curve, power and voltage historic)
- Real time analysis (battery state, SOC state, injection/withdrawal state)

2.3.2. Interaction with other processes

Two modes of operation must be distinguished:

- control by the aggregator: this is the normal mode in which the aggregator draws benefit from this asset in compliance with the contract concluded with the DSO
- DSO control: this is the DSO mode implemented in the event of a constraint or incident on the electricity distribution network

In the case of DSO control, the aggregator is no longer in charge of controlling the battery. It must substitute this asset for another to provide the services it is committed to provide (collective self-consumption, valorisation on the markets, valuation as an ancillary services for the TSO). When switching from normal mode to DSO mode, the aggregator needs to mobilize other resources in its flexibility portfolio.

In the case of aggregator control, the asset is aggregated to the virtual power plants that are valued by the aggregator on different value pockets. The dispatch of this asset is ensured taking into account the following elements:

- local generation forecast: local generation impact the operation as the local generation may be stored locally to from the reduced distribution tariffs available in collective self-consumption scheme[12]

- Maximum number of cycles per day and per period considered (year, duration of the contract)

- Maximum depth of cycles

- Storage efficiency

- Price per activation: price of stored energy, variable cost of activation

According to the use case and especially in case of islanding, the DSO may set up constraints on the minimum electricity storage of the battery: these constraints are fixed in the contract between the aggregator and the electricity distribution system operator. The aggregator considers this minimum storage below which it cannot continue electricity withdrawals from the battery so that it remains operational in case of needs of the DSO.

2.3.3. Service check

The purpose of the service check is to ensure that the aggregator has complied with the contractual constraints. This control can be done ex-post or ex-ante to ensure that the constraints of use are respected at every moment by the aggregator. This can be envisaged at two levels:

- Either at the level of the command-control chain if the aggregator is using the DSO's. Indeed, the DSO can validate the orders before they are transmitted to the storage. The advantage is that the cost of the control chain could be shared through a service fee including a part of the running cost for the control chain. The disadvantage is that the responsiveness of the command control chain of the DSO may not be sufficient to extract value on all value pockets;
- Or at the level of the BMS (Battery Management System) which could be programmed to accept from the aggregator only the orders respecting the contractual constraints. The advantage is that the aggregator is free to implement the control chain corresponding to the selected value pockets and can therefore potentially extract more value. On the other hand, it is not certain that the DSO can accept to use the

[12] According to collective self-consumption distribution tariff

chain of a tier to ensure the security of the distribution network. The costs could not be shared.

In the frame of Nice Smart Valley, the service check is performed ex-ante by the DSO IT as the aggregator is using the control command chain of the DSO.

The software program enables the DSO to remotely control the asset and have access to all the data needed to check the service

- Before placing the aggregator's activation order the program will check the load curve, depth cycle, number of cycles ensuring consistency with the contract. In case of a gap between the contract and order requests, the order won't be implemented and the aggregator will have to review its demand.
- After activation operation: the program will check the match between order sent and real data (load curve analysis), SOC state, cycle number to guarantee the conformity of the battery state according to contract.

Specifications:

- the head meter is the reference for the load curve
- The battery will be returned at a predefined SOC, which means the DSO will check whether it is OK. In case of non-respect of the contract commitment, the DSO will apply a contractually defined penalty fee
- A number of discharge cycles will be defined by contract between DSO and aggregator and followed by the software.

2.3.4. Impact on balance responsible parties and other market players (Engie)

In normal mode, the Enedis battery is managed and programmed by Engie either directly or via the DSO IT[13]. In constraints management mode for the distribution grid, this battery is operated by Enedis. In both modes, Enedis' battery is located within Engie's balancing perimeter.

The impacts from one mode to another are as follows:

- For the balance manager:
  - In the case of Carros, there is no impact because there is an alert in day ahead and this is considered in the programming process
  - In the case of Sainte Marguerite, the impact is very small on Balance responsible parties and is rather positive with the current regulation: Currently, during islanding mode, electricity is supplied from diesel genset owned and operated by the DSO. The supplier is paid by the customer for this electricity and the BRP is paid by the TSO as its balancing perimeter is long. The unbalance price is lower than the day ahead market price. However, the supplier do not pay the DSO for the electricity injected during the islanding mode. Those costs are ultimately supported by all French consumers through

[13] In the Nice Smart Valley framework, Engie defines load curve according its strategy use and Enedis will input the order into to battery's IHM as required by aggregator.

the distribution network tariff. As the considered electricity volumes are small, the impact at the end of the day is small.

- For the energy community manager:
  - In the case of Carros, there is a day-ahead consideration on days when storage cannot be used. In this case, Engie will incur an additional cost due to the impossibility of using local storage to provide its customers with the remote storage service. In this case, Engie can occasionally rely on a remote storage or ensure storage via the market.
  - In the case of Sainte Marguerite, the Engie's community management service is suspended due to the switch to island mode. Indeed, in this case, electricity flows between sites would be controlled by Enedis to maintain the power supply of the area.
- For the aggregator, the impact must be managed: during the constraint mode, as the storage is no more available for other services supply for instance ancillary services. Therefore, the aggregator must consider this in its portfolio management and either alert its flexibility customer for this failure either mobilize other flexible assets.

2.3.5. Open issues

Penalty scheme if contractual performances are not delivered by Enedis

In the plan envisaged in Nice smart Valley, Enedis is responsible for maintenance and commits to a level of availability. In the short term, such products would be rare and would not require a complex tracking of failure and penalties. A penalty pro rata temporis would be sufficient. However, in the medium term, if volumes were to increase, a finer method of penalties might be necessary and be taken into account in contracts between network operators and aggregators. At this stage, this study was not conducted as part of Nice Smart Valley.

Penalty scheme if aggregators do not respect contractual commitments

In normal mode of use, the aggregator must operate the battery according a contract set up with the DSO, the technical threshold will be defined by contract. Therefore, in the case there is an ex-post check (see 1.3.3), if the aggregator does not respect the commitment then, DSO has to structure a penalty scheme that is not analyzed in Nice Smart Valley.

Sizing method to optimize value

The use of aggregator storage is intended to improve the profitability of the set up of such an asset by the DSO. However, in our use cases, the use is constrained by the minimum level of load to be maintained in the case of islanding. Nice Smart Valley did not study optimization of sizing by increasing the energy storage capacity. Yet, the cost of such an increase could be offset by the increase in value extracted from storage. Indeed, the extra cost paid here by the DSO would relate to battery modules but converters and civil engineering which represent on average 2/3 of the cost of storage would already be paid. Thus, doubling the storage capacity would result in a one-third overhead while the potential for recovery would increase considerably. This economic optimization should be further studied.

2.4. Contract Principles

Purpose of the contract

The purpose of the contract for the DSO is to delegate to a third party aggregator, during a given period, the valuation of an electricity storage device owned by the DSO. The aggregator receives the value resulting from the management of this asset and remunerates the DSO in return for the provision of this asset. The valuation of this asset can be conducted by the aggregator in all TSO energy and capacity markets and ancillary services as long as it is compatible with the operating constraints defined in this contract.

The DSO also wants to use this asset when it is necessary for the proper functioning of the electricity network. The contract defines the conditions under which this usage is possible.

Conditions of awarding

The aggregator is selected by the DSO after a call for tenders respecting the purchasing rules to which the DSO is subjected. This call for tenders is public and the attribution rules are transparent and defined upstream.

During a given operating period, there can only be one aggregator in charge of the system.

Storage description

The contract defines the main storage characteristics enabling an aggregator to commit to this service:

- Power of converter (kW)
- Useful storage capacity (kWh)
- Storage efficiency (%)
- Consumption of auxiliaries

Availability

During the contractual period, the DSO is responsible for the asset maintenance. Therefore the DSO guarantees the storage availability to the aggregator.

Some scheduled outages are defined by the DSO when building the contract. In case of changes in the intervention schedule, new dates are defined in agreement with the aggregator. The number of scheduled unavailabilities is set in days.

A number of unforeseen unavailabilities are defined in the contract in terms of number of days and maximum number of consecutive days. The number of unforeseen unavailability days encompasses the maximum number of days that Enedis uses the battery to meet local needs.

If there is more unavailability days than expected in the contract, penalties may be applied by the aggregator to the DSO.

Use by the DSO

The DSO can only use the battery to solve constraints located on distribution network behind the same MV/LV station than the battery.

Usage constraints

The usage constraints to be described in the contract are the following:

SOC level to be kept after a D-1 call or the SOC level to be kept in any cases.

Number of cycles to be respected for maintenance costs reasons:

- Maximum number of cycles per day
- Maximum number of cycles per year

These constraints are validated ex-ante by the DSO via the command control chain or the Battery Management System (BMS) of the storage.

Delegation period

The contract specifies the period during which the valuation of the storage is delegated to a third party aggregator.

This period is defined by a start date and an end date. This delegation is not interrupted by the fact that the DSO manages from time to time the storage to meet its operational needs on the distribution network.

Remuneration of DSO

The aggregator remunerates the DSO according to a fixed annual premium in Euros.

This premium level is detailed weekly.

Payment modalities for energy transfers between DSO and aggregator

Throughout the delegation period, the aggregator holds the contract of access to the distribution network and the contract of energy withdrawal / injection.

When the storage is used by the DSO, some electricity is consumed (efficiency losses and auxiliary consumption).

Moreover, in the event of a different SOC between the transfer of storage control to the DSO and the transfer back to the aggregator, it means that some energy has been consumed or injected. As these withdrawals or injections are charged to the aggregator's contracts, the associated financial flows must be compensated between the aggregator and the DSO.

The energy flow is measured by the head meter of the distribution network manager.

These compensations are performed under the following conditions:

- For share of network charges (TURPE): conditions of the variable part of the distribution network tariff subscribed by the aggregator
- For Energy share: SPOT day-ahead price averaged over the period of use of the storage by Enedis

- The taxes are paid according to the following rules:
  - Taxes linked to auxiliary consumptions are billed back-to-back to the DSO
  - Taxes linked to the battery consumption are related only to efficiency losses. These losses are evaluated as follows: Losses = SOC1-SOC2 + withdrawal-injections. This energy quantity is taxed as defined in the law and is invoiced to the DSO.

Penalties

In case of storage unavailbility beyond the maximum number of days mentioned in the contract, the DSO will give back a part of the fixed part (prorata temporis) at averaged price of the weeks during which the unforeseen outages occurred. The number of days that are invoiced corresponds to the number of days of total unavailability minus the maximum number of uneforeseen unavailabilities mentioned in the contract. If the number of days to be invoiced is negative then there is no penalty to be paid by the DSO.

If this number excess more than 10 working days, this penalty payment is increased by X% for the days beyond the 10 working days.

Responsability

During the delegation period, the DSO, as owner of the storage and responsible for its maintenance, remains responsible for any damage to property and persons as long as the operating programs emitted by the aggregator and applied to the battery comply with the constraints defined within the contract.

Force majeur

In case of a situation that could be qualified as force majeure, the DSO is released from its obligations of availability during the duration of the force majeure situation.

Early termination of the contract

The contract may be interrupted by any counterparty for real and serious reasons. In this case, the counterparty wishing to interrupt the contract must notify the other one 3 months in advance by registered mail.

In the event of early termination of the contract at the request of the distributor, the DSO reimburses the fixed portion corresponding to the weeks remaining at the end of the 3 month notice. A premium of X% of the total value of the contract is added to this value, representing a flat-rate for the losses of the aggregator induced by the anticipated end of this contract.

In case of interruption at the request of the aggregator, it recovers the fixed portion corresponding to the weeks remaining at the end of the 3 month notice. A premium of X% of the total value of the contract is added to this value, representing a flat-rate for the losses incurred by the DSO by the early termination of this contract.

3. FLEXIBILITIES FOR LOCAL GRID CONTRAINTS

The Flexibility use case aims to test the use of flexibilities managed by aggregators to resolve constraints on the distribution grid as part of a local mechanism.

The project endeavoured to answer the following two main questions:

- Can the voltage and current constraints encountered in the case of a reconfiguration of the distribution grid (incident or works) be resolved by means of flexibilities activated as part of a local mechanism approach?
- Could a local flexibility mechanism thereby facilitate the integration of Renewable Energies and Electric Vehicles, which are potential generators of electrical constraints on the distribution grid?

3.1. Products

3.1.1. Grid constraints: context and definition

Current constraints

The capacity or current constraint is the most impacting for the distribution grid as it can lead to its destruction or faster deterioration. It appears when the nominal current capacity of structures is exceeded. These constraints are currently monitored by Enedis' control centres at MV feeder level and HV/MV transformer thanks to alarm devices. As a last resort (after grid reconfiguration), a current constraint can then lead to deploy generators in order to avoid load curtailment.

Voltage constraints

The voltage on the French low-voltage network is limited by the regulation to 230V +/-10% between phase and neutral, to ensure a uniform supply quality throughout the territory. When the voltage goes beyond this range, that causes a deterioration in the quality of the supply, which could, for certain sensitive processes, result in faster equipment wear, or even malfunctions. The Linky smart meter is equipped with an overvoltage protection (after 5 sec above 270V between phase and neutral), as are the production assets connected to the distribution grid, meaning that overvoltage can also lead to an interruption of supply.

Scope of Nice Smart Valley

The here described local flexibility mechanism addresses only current and voltage constraints at MV level (including HV/MV transformers in primary substations). Besides, as mentioned in chapter 3.1.2 and in D9.1, constraints may only appear in case of grid reconfiguration in the demonstration areas.

3.1.2. Useful flexibility for the DSO

The demonstrator areas were chosen based on experience feedback and a preliminary study conducted by Enedis which identified potential constraints whenever a device on the grid is inoperative. This chapter presents a short synthesis of the investigation results, see D9.1 for more details.

An initial simulation campaign made it possible to detect constraints in degraded operating situations (i.e. when it is impossible to use a device on the grid). Although they are very rare, these situations made it possible to identify real cases in which flexibility could be useful for the distribution grid.

Table 1 – Breakdown of types of constraints by area

Area	BROC CARROS	ISOLA	GUILLAUMES
Current constraints	X	X	X
Voltage constraints		X	X

The Guillaumes area is a rural area with very long grid lines resulting in voltage constraints. In addition, the small number of MV feeders available to rescue the affected networks can also lead to current constraint.

A specific feature of the ISOLA area is the use of an HV/MV substation which is used only as a backup solution in case of an outage on the single HV line of the transmission grid feeding ISOLA primary substation. This backup substation is not sized to provide a complete backup permanently. A current constraint is therefore very likely to happen whereas voltage constraints may appear for the same reason as in the Guillaumes area (rural/mountain configuration).

The BROC CARROS area is an urban/suburban area, so the grid lines are shorter and of larger capacity, and the constraints which appear are constraints of exceeding the maximum permissible current by a cable at the level of a backup feeder and an MV cubicle.

3.1.3. Products

To enable the aggregators to recruit effectively in the Nice Smart Valley areas, the characteristics of useful flexibility products have been defined thanks to simulations whose results are summarized in this chapter (see D9.1 and D9.3 for more details). These characteristics contain, in particular, the useful flexibility volumes, the periods of stress and the potential number of activations during the year (see D9.1 for more details).

As mentioned in D9.3, the precise location of a flexibility resource has an impact on the volume of flexibility needed to alleviate a constraint. This impact has been shown to be significant for voltage constraints (up to as much as 3 times of the flexibility volume needed if the flexibility resource is not well located), whereas it is low for current constraints (X kW of flexibility always solve at least a X kW constraint). As a result, the process developed in Nice Smart Valley only addresses flexibility for current constraints, and the only considered requirement regarding flexibility resource location is to be inside the geographical perimeter defined by the DSO.

The simulation results showed the constraint occurrences described below, which were calculated with the assumption of an N-1 system over two years, which corresponds to an exceptional situation.

- 2.5 MW of flexibility located in the geographical perimeter defined by the DSO would resolve all the potential constraints in winter time which may appear from December to January between 10.00 pm and 5.30 am in the ISOLA area.

- 0.5 MW of flexibility located in the geographical perimeter defined by the DSO would be sufficient to resolve all the potential constraints that could appear in summertime in July between 11.00 am and 2.30 pm in the CARROS area.
- The useful flexibility volume in the GUILLAUMES area would be 1.2 MW to 3 MW in order to resolve all the potential constraints that could appear from December to February over a major period of time for the U constraints[14] (see Table 2).

Table 2 –Summary of the potential for flexibilities, assuming an N-1 configuration over a period of two years

Area	Isola	Carros	Guillaumes			
			Feeder 1 I constraint	Feeder 2 I constraint	Feeder 1 U constraint	Feeder 2 U constraint
Maximum flexibility volume	2.5 MW	0.5 MW	0.5 MW	0.7 MW	1.9 MW	1.1 MW
Number of 10 min. constraints	30	7	1	5	25	81
Number of constraints lasting between 10 min. and 40 min.	25	2	2	7	26	69
Number of constraints lasting more than 40 min.	25	0	2	6	40	171
Months in constraint (>=80% of constraint occurrence over a year)	December January	July	December January	December January	December February	December January February
Potential hours in constraint	10.00 pm to 5.30 am	11.00 am to 2.30 pm	11.00 pm to 1.00 am	7.00 pm to 4.00 am	5.00 pm to 7.00 am	12.30 pm to 11.00 am
Resulting occurrence (>=10 min) every[15]	64± 6 years	390± 60 years	320±40 years	104±20years	Non meaningful results	Non meaningful results
Resulting occurrence (>=40 min) every year[16]	146+- 15years	(None)	570+- 130years	340+- 50years	Non meaningful results	Non meaningful results

[14]The characteristics of voltage constraints are presented as an illustration: as mentioned above, the process that is presented further in the document only addresses current constraints.

[15] Assessed with a Poisson process using the previous computation results and the normative rate of failure of HV and MV equipment.

[16] Assessed with a Poisson process using the previous computation results and the normative rate of failure of HV and MV equipment.

It should be noted that these simulations highlighted differences between product characteristics on each of the three areas like the type, season and time slot of constraints. For practical reasons and as N-1 situations in which constraints may occur were very unlikely to happen during the demonstrations, the project decided to agree on only one type of product characteristics to be tested, complying with most of the situations. These characteristics are defined in Table 3 (see D9.2 on customer recruitment for more details)[17].

Table 3 – Nice Smart Valley Flexibilities product characteristics

Seasons	Summer		Winter		Mid-season	
Days	Week	Week end	Week	Week end	Week	Week end
Time slot	10-16h 18h-20h	10-16h 18h-20h	19h-6h	19h-6h	6h-10h 16h-18h	6h-10h 16h-18h
Process	J-1	J-1	J-1	J-1	J-1	J-1
Minimum duration	30 min	30 min	30 min	30 min	30 min	30 min
Maximum duration	2h	2h	2h	2h	2h	2h
Max. time between activations	2h	2h	2h	2h	2h	2h
Max number of activation/day	2	2	2	2	2	2
Max number activation per year	60					

3.2. Valorisation mechanism

3.2.1. Assessment of the local upper bound of flexibility value for Enedis

Note that the details of the following study are available in section 2.3 of the D9.3.

During Nice Smart Valley, Enedis has defined a mathematical method to assess an upper bound of flexibility value for the DSO. It has been calculated based on the value of the undistributed energy that Enedis could not supply to its customers after very specific incidents on the MV or HV grids. In this study, no other way to supply customers has been considered as the value is often higher by calculating the undistributed energy than the cost of the temporary solution.

It is important to note that these values do not represent what Enedis will pay for a flexibility service or even what Enedis would pay to the customer for the missing energy as this value is only used as a reference to assess the needs for grids reinforcement. It only gives an insight

[17] It should be noted that these products were defined according to simulations made in Nice Smart Valley and based on local hypothesis, for demonstration purpose. These results do not necessarily fit with other types of contexts or locations.

into the boundary cost which limits the amount Enedis would ever pay for a temporary solution.

As explained in the D9.1, today, only a few primary substations have a non-zero upper bound. Three of these primary substations have been analysed in Nice Smart Valley.

The results are shown in the table below:

Table 4 – Local upper bounds of flexibility value for Enedis

	Carros	Isola	Guillaumes feeder #1	Guillaumes feeder #2
Type of grid	Urban	Isolated rural	Rural	Rural
Incident considered on	MV	HV	MV &/or HV	MV &/or HV
Upper bound of flexibility value	< 1 €/year	298 k€/year	7 €/year	8 €/year
Maximum volume of flexibility	0.5MW	20MW[18]	0.5MW	0.7MW
Upper bound of flexibility value over the volume of flexibility	< 1 €/MW/year	15 k€/MW/year	11 €/MW/year	16 €/MW/year

On Carros and the two Guillaumes feeders the upper bounds are very low as the duration of potential electrical constraints does not exceed a few hours per year. This statement associated with the likelihood of occurrence of the considered incident lead to a local highest boundary of less than 8 €/year.

On Isola, the HV incident that requires a MV N-1 configuration leads to an upper bound at 298 k€/year. This relatively high result can be explained by the two following points:

- The studied HV incident impacts two primary substations.
- There is no other HV line from another area able to supply the local consumption. The French TSO has the possibility to put a HV N-1 configuration but needs to inspect its lines before by sending a helicopter on the field. As this operation takes from 4 hours to 14 hours - depending on the moment of the day and the weather - some part of the local customers may be disconnected for the same duration.

Note that this upper bound of flexibility value seems high enough for aggregators to be interested in contracting flexibility. However, as this upper bound does not represent what Enedis would pay for a flexibility service –or what the actual costs are in case of such an incident -, there is a need of refining the flexibility value to go further.

[18] This result is different from what has been explained in the D9.1 and in chapter 3.1.3 of the present document. The reason why there is such a difference relies on the fact that Enedis studied the dynamics of the incident (with grid configuration along the process), leading to higher volume of useful flexibility than 2.5MW as mentioned in *Table 2*. On Isola, the different events that lead to the final N-1 configuration were indeed not considered in the previous analysis. This study is further detailed in D9.3.

3.2.2. Funding systems: fixed and variable portions

Flexibility can be of use to the DSO for:

- ⇨ Network planning, by substituting to an equipment upgrade or creation, and planned interruption, by substituting to a topology change or a power generator. A flexibility would then insure that in case of the generation or the consumption peak, the system would stay within the authorised limits. If the flexibility is either unavailable or failing, the DSO would then face an unforeseen interruption, that would have been otherwise avoided through a "classic" investment, inducing extra costs (penalties for non-delivered energy, last minute works, last minute order of generators, and so on)
- ⇨ Network operation by substituting to emergency resupply equipment. In case of pre/post unforeseen interruptions, the DSO has other means to deal with the situation and the flexibilities will be activated on a merit order list system: in case of unavailability the DSO will only go through the merit order list and activate the next most interesting solution without supporting extra charges for starting with a flexibility. Besides, the flexibility can be used in conjunction with other solutions and consequently only solving partly the problem.

Consequently, the different values of the flexibility ensue from its availability and its activation making it normal to divide the value between a fixed part (for the capacity booking – ensure that the flexibility will be available when needed) and a variable part (for the injected/consumed energy to lift the constraint). The DSO would pay a fixed part only if a capacity was reserved, i.e. for an investment deferral or a planned interruption.

To value both the availability and the activation of a flexibility and pay adequately the Flexibility Service Provider (FSP), the DSO must assess the delivered service through a set of criteria, such as:

- ⇨ Energy generated or consumed during the flexibility compared to the assessed baseline curve
- ⇨ Activation period within the DSO required timeframe
- ⇨ Activation at the right time (Full Activation Time on par with what was offered)

The ability of the DSO to assess the flexible energy and the precision with which the DSO can do it will be critical to make them relevant.

Any activation failure will lead to penalties on either or both fixed and variable parts.

3.2.3. Penalty mechanism

As said above, flexibility has both a performance obligation on availability and activation making it necessary to enforce penalties on the fixed and variable parts in any flexibility contract. The DSO must however choose a penalty that will incentivise the FSP to deliver the promised service without deterring them into entering into the local flexibility market. For that purpose, the DSO can choose between two models:

- ➢ Either a penalty based on the extra costs induced by a service failure
  - ○ A cost based penalty will cover all the DSO costs induced by a service failure but will be too unpredictable for the FSP. This model might induce a depletion of the field due to FSP high risks in case of failure. Besides it will be

complicated for the DSO to assess precisely the extra costs and clearly stick the responsibility of those to the flexibility failure (is the flexibility failure responsible for the whole incident? Only partly? To what extent?). Furthermore, in case of a service failure where no incident occurs (e.g. due to a DSO incorrect forecast), the FSP will be liable to a penalty… without any fee.

- Or a penalty working as a package based on the value of the delivered service
  - A package penalty makes it easier to forecast the penalty costs for both DSO and FSP but might not cover the whole cost of failure for the DSO. It is however proportionate to the service cost making it easier for the FSP to support.

Enedis considers that market players must be fully informed of the induced costs of a failed activation to build their offers and would as a consequence favour a package penalty.

The Nice Smart Valley demo does not include penalty since there was no performance obligation and no money exchanged between the DSO and the FSP making it all but impossible to impose penalties. From a hypothetical point of view, Enedis has been working on several penalty schemes (for fixed and variable parts) in both the "Article 199 experimentation" (named after the given article in the French Energy Transition Law, 2015) and its call for inputs on the local distributed flexibilities (published in November 2018):

Part	Penalty formula	Comments
Fixed part - Model 1	$Fixed\ Part_{Market\ Player} = \frac{FixedPrice_{Offer} \times \beta}{Number\ of\ planned\ activations}$	
Fixed part - Model 2	$Fixed\ Part_{Market\ Player} = Fixed\ Price_{Offer} \times Factor_{Variable,t-1}$	With $Factor_{Variable,t} = Factor_{Variable,t-1} + \frac{Volume_{Failed}}{Volume_{Expected}}$ And $Factor_{Variable,t=0} = 0$
Variable Part	$Variable\ Part_{Markeet\ Player} = VariablePrice_{Offer} \times (Volume_{Actvated} - \alpha \times Volume_{Failed})$	The α factor is set at 35% in the Article 199 model contract.

Table 5 Examples of penalty formulas

3.2.4. Costs representativity for an aggregator

In the short term, local markets are likely to be subject to weak competition due to a limited number of players. In this context, the electricity distribution system operators are exposed to a price risk of the flexibility. Indeed, the Aggregator's product prices are not necessarily representative of the costs of the aggregators. This may lead the DSO to potentially opt for other solutions than flexibility.

These costs include fixed costs (prospecting, contractualization, customer portfolio management, implementation of the equipment required to activate the flexibility and

possibly a cost representing the customer's remuneration) and variable costs (customer remuneration per activation).

On the distribution network, most customers do not have purchasing or contractual monitoring functions that would allow them to follow a variable remuneration. Hence, they often prefer a fixed remuneration per year. This can take a monetary form or the form of services.

For flexible customers whose activation cost is significant, a variable cost depending on the amount of modulated energy must be taken into account (diesel engines or CHP for instance).

Thus, it appears that the costs Cf for an aggregator for a given flexibility capacity can be written as Cf = A + B * number of years + C * activations (number or energy). Where A is the initialization cost of the capacity, including: the installation of the monitoring and control systems, the costs of prospecting and contracting, the costs of creating the client in the IT tools. B is the annual cost including: the yearly remuneration of the client, the running cost of the necessary information system (pro rata of the capacity concerned in relation to the entire portfolio) and the cost of client contractual monitoring. C corresponds to the compensation for client availability.

On one hand, aggregators must cover on a local mechanism these costs which are mainly fixed. On the other hand the number of activations is not determined in advance. Therefore, the aggregator must either (1) get an annual fixed remuneration covering the cost of the flexible capacity while the price per activation is capped, or (2) must be able to bid the capacity at a price without ceiling so that it can absorb its costs over a potentially small number of activations.

In the case of solution (1), it would be useful in the short term to ensure the representativity of the fixed and variable costs of the chosen aggregators because of the low competition. In the case of solution (2), the aggregator should not have to adjust its bid price to its variable costs. It should include in its price its fixed costs and the risk of not being solicited for several years by the DSO.

Solution (2) seems irrelevant in the short term for at least two reasons:

1- There is factually a ceiling for activation prices since the DSO compares the cost of flexibility offers with the alternatives available to it;
2- In a situation of weak competition, it does not seem healthy to allow a flexibility activation without a price limit.

3.2.5. Competition issues

General principles: Competition between several actors should be encouraged to minimize cost of flexibility. Minimal cost of flexibility for the electric system is reached when a healthy competition between market players occurs. There is no specific good number of players, it all depends on the market setting and the overall development of the electricity sector. If the seller or buyer has still dominant position, there is always a way to ensure competition for example by imposing more regulations.

The objective is then to ensure fair and transparent competition between actors and a level playing field between the different solutions (DSM, storage, generation) available to fulfil DSO needs.

Moreover, on such new market, it is important that rules make the market access possible to newcomers and not only incumbent players. However, due to monopolistic heritage or to dominant position on the market, it can be easier for some actors to develop a flexibility portfolio than for newcomers.

The following measures could be taken to favour the entry of new aggregators and to ensure fair competition with potential well-established players:

- Separation of the roles between flexibility aggregator and energy supplier;
- Market organizer must be neutral (clean energy package);
- New opportunities must be available for newcomers every years either through market size development either through contract duration limitation to 1 year between DSO and aggregators for a significant part of the market to enable new comers to contract.

3.2.6. Mechanism transparency

Generally speaking, the market design must be explicit and transparent to foster the development of competition and to encourage the development of flexibility capacities where they are required and valuable.

As an example, Engie as an aggregator suggests the following data to be published:

- Data regarding the local flexibility value:
    - If the market doesn't exist yet, indications of flexibility value by the DSO at precise locations on the grid and at different horizons are useful for actors to develop their portfolio and hence to create the market. This data is important to encourage the aggregator to develop flexibility portfolio knowing what can be the value in front of the recruitment investment
    - In the case of existing local market, historical and forward data on orders, clearing or min/max prices, volumes, actors involved on the market. However, the market transparency must respect the confidentiality of the offer. Therefore, a minimum number of players -to be determined- is required. → When local players are already active, this data is important to encourage new players to come and introduce competition to develop cheaper flexibility for the DSO ; moreover this data is required to check whether the local market works properly
- Technical data regarding grids constraints level:
    - Indicators of the distribution service quality at local level. This data is important to anticipate where flexibility could be useful in the future and target those area for the flexibility development; it is also important to communicate data to the local flexibility providers to enrol and commit them on long term.

Market can be organized with regular tenders or in an opportunistic way, according to punctual DSO need. In both cases, the periodicity of the mechanism is key for the aggregator to have vision of its remuneration and therefore to encourage development of flexibility offers in the zone. This periodicity must be known in advance, and published, as well as other market rules:

- Offer selection mechanism (merit order mechanism) and offer remuneration mechanism (pay-as-bid, pay-as-clear…);
- All the data linked to the market mechanism must be shared between the players: flexibility activation costs, number of realized activations, total need for flexibility, real time data on prices, orders and volumes;
- Market rules: market horizon, type of orders, remuneration strategy, market operator, regulations rules, rewards and penalties in case of activation/non-activation.

It should be noted that data flows ensuring the mechanism transparency should be consistent with the size of the market and the value at stake for the electric: too many data for a small market would lead to a useless complexity.

3.3. Processes

3.3.1. D-N process

This process only deals with "planned" current constraint related to DSO workplan inducing grid reconfiguration or investment postponement. It does not address the case of unforecasted flexibility requests related to grid incidents.

Description of the business needs underlying this process:

1- The DSO foresees constraints on the network over a given period, taking into account weather forecasts and grid configuration. The DSO wants to make sure that flexibility can be available at this moment
2- The DSO makes a call for tender in D-N to make sure aggregators can activate flexibility. DSO pays the aggregators for this capacity guarantee
3- On D-1, the DSO can launch a new call for tender. Aggregators already selected and remunerated for their capacity have to post bids (possibly at a capped price to avoid unfair energy prices. In this case the number of activation would as well have to be limited)
4- The initially selected aggregators, are not necessarily retained a second time if other competitors can provide cheaper flexibility

Flexibility exchanges between DSO and aggregators can be divided in several sub-processes with the following main actions:

1. Publication of DSO local future opportunities to use flexibility and definition of local products
2. Prospection and contracting: continuous process

Aggregators prospect clients and contract flexibilities in order to capture value on several value pockets (TSO ancillary services, energy markets, local DSO market). The characteristics of recruited flexibilities are registered by the DSO, with following data:

- Type: producer or consumer
- Direction of the flexibility: up and/or down
- Validity end date of the customer consent for the use of metering data
- Location of the customer: creation of a link between the customer and an e-flex entity[19], making it possible to make the flexibility sources anonymous for the operator who will implement the mechanism subsequently.

The registration process by the DSO facilitates future activations by keeping flexibilities technical characteristics up to date, and ensure the compliance of the process with data privacy regulation.

3. Tender for flexibility: N days before flexibility activation (D-N)
    - DSO sends solicitation to aggregators (tender), including the location, the time slot, the direction and the volume (power/capacity), according to the pre-defined products.
    - Aggregators bid offers on DSO platform in D-N to answer this demand
    - DSO ranks the flexibility in a merit order list[20]
    - DSO gives notification of flexibility reservation to selected aggregators.

4. Confirmation of activation: 1 day before flexibility activation (D-1)
    - DSO re-evaluate the flexibility, confirms flexibility request for D day and sends solicitation to aggregators committed to activate (that must propose flexibility) and to others aggregators (that can propose flexibility)
    - Aggregators bid offers on DSO platform to answer the demand
    - DSO ranks the flexibility in a merit order list, and informs selected aggregators
    - Aggregators program flex activation for D day (on day D: the flex will be activated).

[19] E-Flex is the flexibility platform developed in the project. See D9.3 fore more details. In Nice Smart Valley, an entity corresponds to an MV node or an MV/LV substation

[20] The project did not assess a method to choose an alternative plan in case of insufficient flexibility volume. This step was not tested during the experiments.

5. Settlement
    - Fixed price: Aggregators committed to activate in D-N are remunerated for their future availability (€/kW) and pay penalties if they do not bid in D-1 or if there flexibility is not available.
    - Variable price:
        - DSO and aggregators collect realized consumption data of each client over the past month
        - They estimate potential penalties by comparing realized vs. reference consumption + flex activation orders (see chapter 3.3.4 on service check)
        - DSO pays the aggregator according to realized flexibilities (€/kWh)
    - Aggregators remunerate their clients (including the potential penalties)

Guarantee of flexiblity in D-N

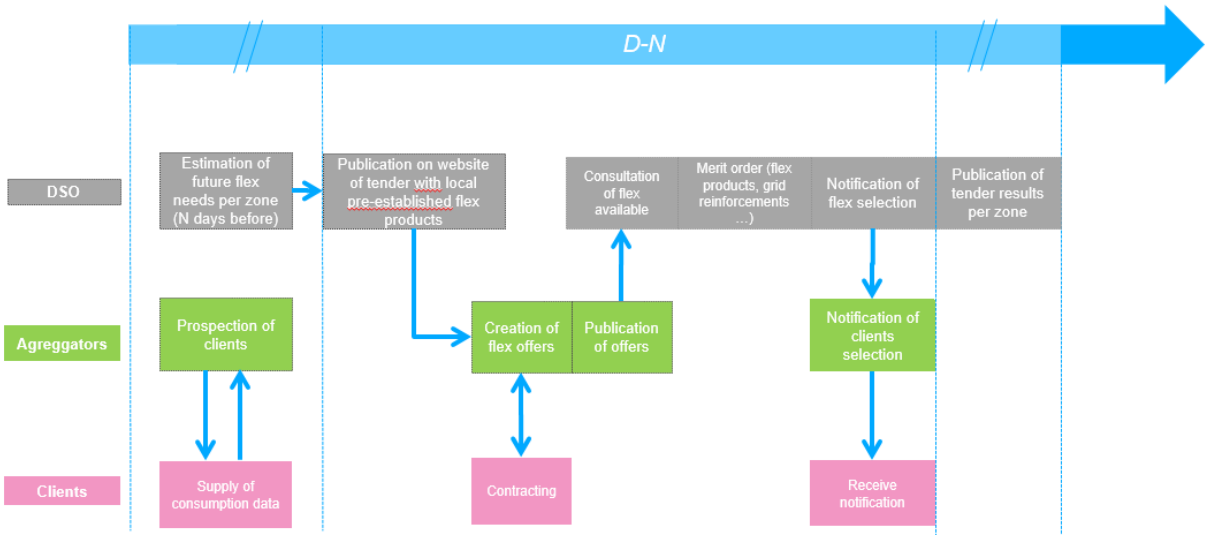

Figure 10 Capacity reservation in D-N process

3.3.2. Introduction of D-N+X step

The process D-N as described above does not include the possibility to adapt the flexibility request between D-N and D-1. However, due to the evolution of weather forecast, as well as unforeseen needs for grid reconfiguration (evolution of DSO workplan, incident on the grid), it seems relevant to open the possibility for the DSO to update its requests as many times as needed along the process. In order to minimize the cost of flexibility reservation for the DSO as well as the potential value of the aggregator portfolio, it is indeed in the interest of all parties to be able to release booked flexibilities or to reserve new flexibilities as soon as possible during the process.

This new step, occurring at D-N+X_1, D-N+X_2,… can be divided into the following sub-processes:

1. At D+X-N, the DSO re-evaluates the need for flexibility.
2. Depending on the results, several options are possible:
    - If the need for flexibility in D-N+X_n is less than in D-N+X_{n-1}, the DSO warns the selected aggregators in order to free up the useless booked capacity. The sooner a booked capacity is freed up, the lower would be the compensation from the DSO to the aggregator (to be agreed upon when entering in contract).
    - If the need for flexibility in D-N+X_n is higher than in D-N+X_{n-1} a new call for tender is published. Depending on the merit order list, the DSO can choose to free up a part of booked capacity to select other offers or just “add” new offers to comply with the need.

It should be noted that this step was not tested during the project and should thus be further assessed before implementation.

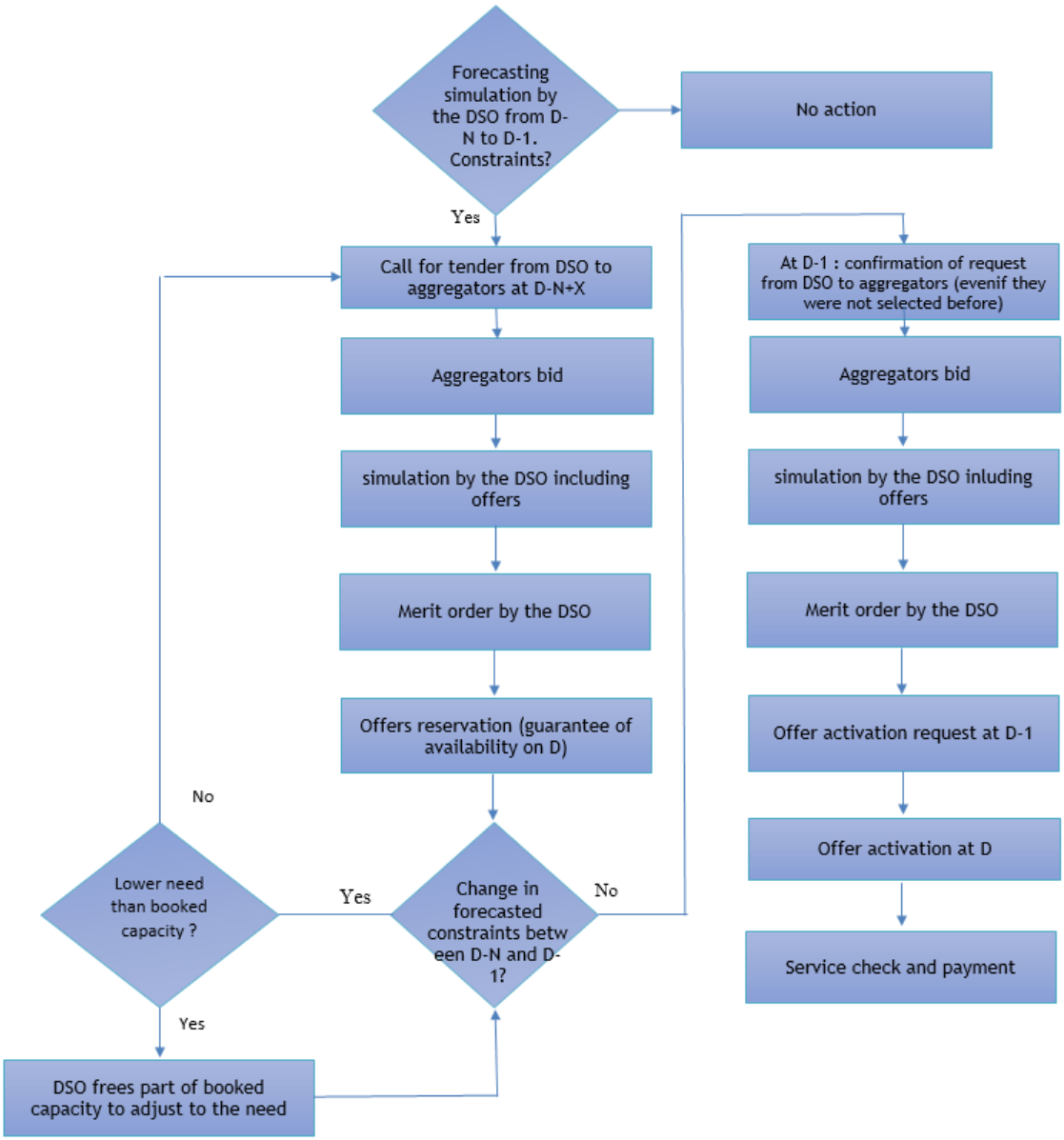

Figure 11 D-N process including D-N+X step

3.3.3. Links with other aggregator processes

Aggregators plan to capture value from other than DSO markets (see D9.2 §3):

- Capacity market
- Tertiary Reserve (Fast and Complementary Reserves)
- Balancing mechanism
- Day-ahead energy market (NEBEF)

Each mechanism has specific constraints but some values could be stacked under certain conditions, among them the fact that flexibility is answering several needs.

The question of cumulation of values is twofold:

1- Is it possible to value the flexibilities of the same site on two different mechanisms from two different flexibilities?

2- Is it possible to value the same flexibility simultaneously with the DSO and with another value pocket?

Concerning the first question, a double valorisation should be possible if it is possible to control separately the activation of each flexibility. If this is feasible, the possibility of a simultaneous valorisation of a site on two mechanisms is a regulatory matter.

Regarding the second question, it is necessary to determine whether the activation of a single flexibility serving two different mechanisms makes the same service as the activation of two distinct flexibilities. The answer depends on:

- how to measure the effectiveness of flexibility
- Moreover, whether the flexibility is or is not the subject of a reservation by the DSO or the TSO

a. Effectiveness measurement of a flexibility.

Concerning cumulation with DSO value, it would depend on the way that flexibility is measured. Indeed TSO and energy markets consider a flexibility as a curtailment on the electric consumption curve, of a pool of clients anywhere on the grid. The DSO need is related to a pool of clients at a specific location on the grid, but the definition of flexibility is still to be defined:

- If DSO flexibility requirement is also a modification of the withdrawal or the injection on the distribution network, as it has been tested in the project, then value cumulation requires optimization and coordination of power available at different time slots.
- If DSO flexibility requirement is to frame consumption or injection of the pool of clients, then engagement on the mechanisms are easier to cumulate as a flexibility engaged towards TSO can be useful at the same time even if the activation is not decided by the DSO. When a flexibility is activated for TSO or market purpose at a useful moment for the DSO, then this flexibility is both efficient and free of charge for the DSO.

b. Reservation or not by a DSO

If the DSO reserves flexibility, then the aggregator must be able to mobilize the desired product when the DSO needs it. In this case, the aggregator must ensure that it is able to deliver the flexibility product expected by the DSO at all reserved times. It will forecast in advance the flexibility availability and will distinguish the share it must reserve to meet the need of the DSO by taking a margin of safety. Excess at a given date may be valued on other mechanisms.

In the absence of a prior reservation, the aggregator will value its flexibility portfolio on all available value pockets and will meet the needs of the DSO opportunistically (1) using the residual flexibility capacity at the national level of its portfolio and (2) in the absence of residual capacity by arbitrating between the potential value coming from the DSO and the

certain value extracted elsewhere on other mechanisms. This process needs some time to be performed. This is the reason why the aggregator needs time to dispatch its portfolio when there is no prior reservation.

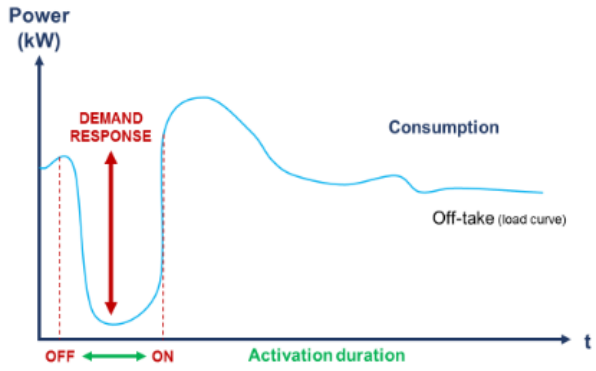

Figure 12 - Load with flexible process

3.3.4. Service Check

The service check involves checking that the requested flexibility has indeed been activated. This is the last step before invoicing. Enedis therefore makes sure that the service corresponds to the offer that it has activated.

The main objective of the service check is to analyse the reality of demand side response by comparison with a benchmark load curve in order to deduce from this the quantity of energy not consumed.

Generally, electricity consumption load shedding can result in edge effects, reflected by a change in the consumption behaviour of the sites activated outside of the activation period alone. There are four impacts on a customer's load curve:

- The volume shed;
- The anticipation effect: Increase in consumption before the start of activation, in order to maximize load shedding and hence the remuneration;
- The rebound effect: Corresponds to the temporary over-consumption on exiting flexibility activation;
- The transfer effect: Corresponds to over-consumption over the period to return to the state close to the scenario without flexibility activation.

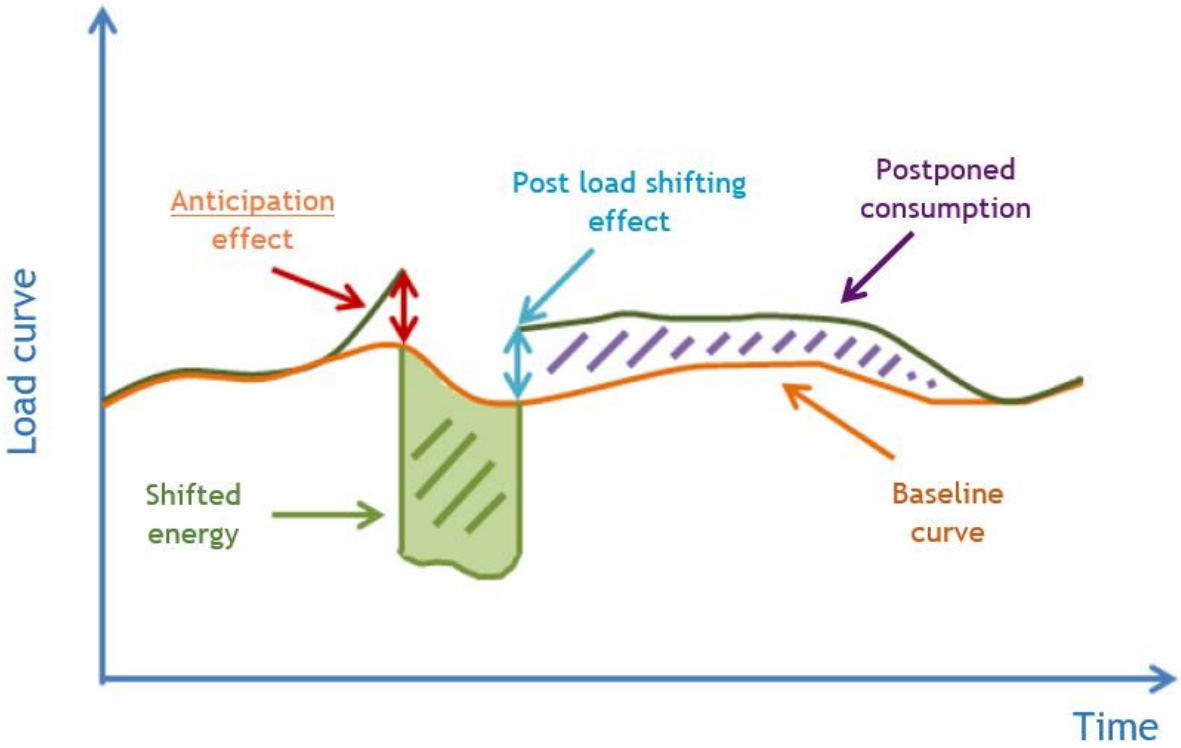

Figure 13 – Impacts of the service check

2.1.1.1 Methods used

The used methods have been applied within the framework of other smart grid demonstrators, and are proposed by Enedis to check the actual load shedding performed on the electricity distribution grid and valued within the framework of the market mechanisms (MA and NEBEF).

Several methods have been used in the Nice Smart Valley project depending on the type of customers. For further details about the performance of these methods, see D9.3.

<u>B2C customers:</u>

For customers with a subscribed demand of less than 36 kVA, it is the sample group method. This method consists in determining the quantity of electrical load shedding in a customer population based on two sample groups: one consisting of individuals representative of the population studied, and the other, a mirror of the preceding group, consisting of customers having similar characteristics to those of the population disconnected but not belonging to said population and not subject to consumption load shedding.

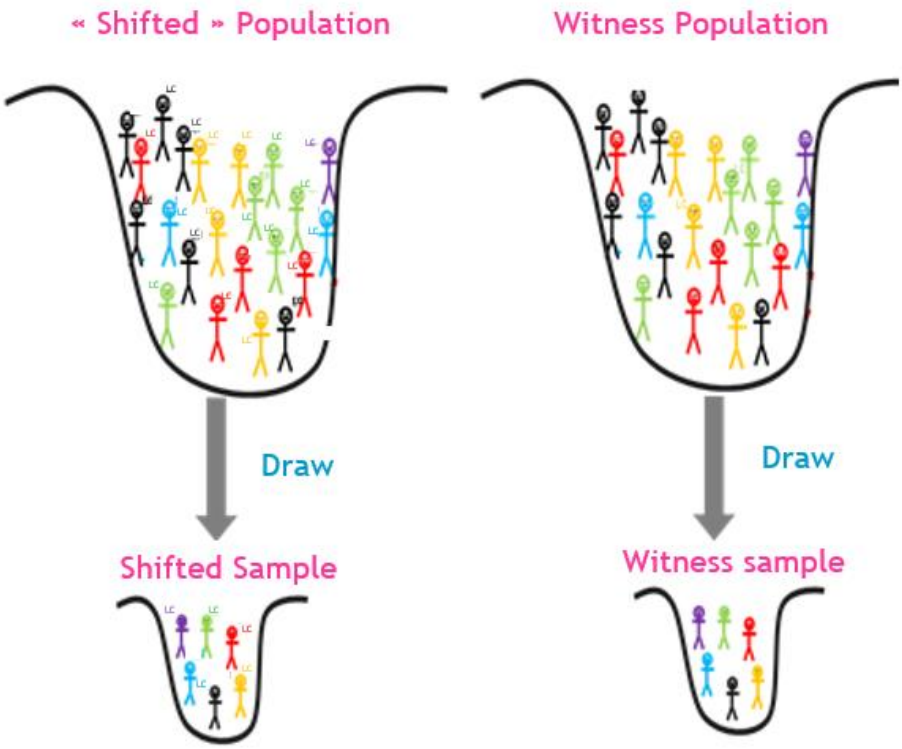

Figure 14 – Sample groups illustration

The method is appropriate for the situation of the Nice Smart Valley demonstrator, with the use of a single sample group: the mirror sample group. A sample group to determine the actual load curve for the disconnected sites is of no interest because this population is small, and their load curve is known precisely by adding together the individual specifications.

<u>B2B customers:</u>

For customers with more than 36 kVA, two methods are used. The first method is that of the closest adjacent K values. The closest adjacent K values correspond more precisely to the day for which consumption is closest to that of D-Day in "idle" moments of the day, in the vicinity of the estimation period. The vicinity thus excludes the periods of activation of load shedding and observation of edge effects. In practice, this leads to a power profile that can be adjusted in energy to comply with the level observed on “idle” days. This adjustment is done for all B2B customers involved in the demonstration. The second method is the SARIMAX method, which involves modelling the benchmark curve of one or more sites at time t as a weighting of the consumption measured for prior times. It makes it possible to deal with the thermo-sensitive sites of the project.

The indicators MAPE (quality indicator of the benchmark curve by comparison with the actual curve) and MPE (indicates the overestimation or underestimation error tendency) were used to evaluate the accuracy of estimation of load shedding.

3.3.5. Impact on balance responsible parties and other market players

The balance responsible party (BRP) is in charge of ensuring the balance between injection and draw-off in a given area, consisting of injections (physical production sites, purchases on the exchange or from other players, imports) and draw-offs (physical consumption sites, sales on the exchange or to other players).

A system established by the grid managers makes it possible to count flows on the grid, to allocate them precisely to the area of the source or destination BRPs, and to calculate, for each of these players, the differences between energy inputs and outputs. The BRPs therefore compensate ex-post financially for the differences they have caused on the system.

The BRP therefore provides the injection and draw-off players having grid connection points included in its area with a financial service of compensation for imbalances. This service is provided via the signature of a contribution agreement. The remuneration paid under the various contribution agreements enables the BRP to generate cash for settlement of the differences and to ensure the margin corresponding to the performance of this financial service.

Apart from this purely financial responsibility, the BRP acquires the means enabling it, before the real-time settlement, to forecast injections and draw-offs. For example, if the BRP anticipates an energy deficit, it may ask the producers in its area to increase their production, or consumers in its area to disconnect, or else buy energy on the market or from a counterparty by mutual agreement. These actions take place in compliance with market rules, and the grid manager is informed, where appropriate, of changes in injection.

The assignment of an injection or draw-off site to a BRP is compulsory, so that the combined action of the BRPs, having a financial incentive to balance their own area, contributes to the overall balance of the grid (sum of all the areas of all the BRPs). Ultimately, it is indeed the transport grid manager which is responsible for the physical balance of the electricity system, and it may, accordingly, have to take control of the management of injections and draw-offs to ensure the balance of the grid, in the time lapse between the last gate closure time and the real-time settlement.

In some cases, the imbalances detected in the area of a BRP are not attributed to it, because they are the cause of a third-party intervention and are therefore considered as outside their responsibility.

This is the case, in particular, when flexibility is activated by a third-party flexibility aggregator having established contracts directly with the injectors in the area of the BRP. This aggregator may have priced this flexibility with the transport manager (management of the national balance, grid constraint, system adjustment) or with another market player.

Although it may have been cut off and is therefore absent from the physical result, the energy traded by the flexibility aggregator is attributed at the settlement of differences to the draw-off area of the BRP having the disconnected injections in its area. Accordingly, the result again becomes the same for it as what it would have been if the flexibility had not taken place. Moreover, this energy is transferred to injection in the injection area of the aggregator's BRP, so the result of the compensation operation is algebraically null.

Such a compensation mechanism exists on the injection points located on the public distribution grid, as exists on the public transmission grid, but it is necessary that it operates for the flexibility asked for by the DSO, as well as by the TSO. A flexibility activated by the DSO can induce an unbalance which the TSO has to deal with. If this mechanism was not established, the result would be an unfair market mechanism leading the BRPs to take financial responsibility for differences beyond their means of control because implemented by third parties. Such a situation would result in an increase in the cost of the balance responsibility service to cover the corresponding risk and ultimately, by repercussion, to an increase in the cost of energy.

3.3.6. Electricity suppliers

On the distribution network, as on the transportation network, the aggregator which has priced the flexibility and activated it is the receiver of the disconnected energy. For each disconnected site, the not consumed energy was, however, sourced by its supplier. This energy is due to the activation of flexibility transferred to the area of the aggregator and priced by it and not by the supplier. A financial compensation is therefore planned for the supplier, to compensate them for the transfer of ownership of the energy and the pricing potential that it offers.

Here again, this provision in application in the market rules established by the transmission system operator should be extended to the market for flexibilities priced with the distribution system operators.

3.4. Contract Principles

Scope of the contract

It should be noted that here described contract principles are the result of the project, and therefore do not necessarily reflect Enedis', EDF's and Engie's position in ongoing discussions about future or actual calls for tender. One of the reasons for this statement is that not all open issues have been solved or addressed.

The purpose of the contract is to set a framework enabling an aggregator to deliver flexibility services to the DSO according to the mechanism described in this deliverable. It is then applicable to a mechanism under the following conditions:

- Forecastable constraints: as mentioned in chapter 3.3, the process fits with so called "foreseeable constraints" as investment postponement or work planning. It does not fit with constraints occurring right after an outage.
- No Service commitment: capacity reservation can be offered and bought at each flexibility call for tender at D-N, with related penalties. There are no pre-established service guarantees in the contract described here.

Content

The contract opens access to calls for tender in a specific area with related pre-defined flexibility product characteristics by the DSO. This means in practice that it enables an aggregator to declare a portfolio on the flexibility platform, and to keep it up to date, in order to be able to submit offers to calls for tender published by the DSO. It describes:

- The geographical/technical perimeter of the mechanism
- The product characteristics of the local mechanism
- The process of the mechanism: time slots to open a call for tender by the DSO, to submit offers by the aggregators, to select offers by the DSO, to make a request of activation on selected offers
- The conditions needed to register flexible prosumers on the flexibility platform: compliance with the geographical perimeter and data privacy rules (see below)
- Funding and payment process, including service check (see below)
- IT Technical specifications to communicate with the flexibility platform
- Share of responsibilities and risk management regarding data privacy, impact on customer processes, energy suppliers, BRPs and possibility to stack the value with other flexibility/mechanism
- Commitment to avoid gaming

Data privacy

For each new flexible prosumer that an aggregator wants to include in its offers, a consent regarding metering data use for service check is mandatory before any registration on the flexibility platform. Besides, it is of the responsibility of the aggregators to keep its portfolio up-to date, that is to say to delete any prosumer whose consent would come to an end or who would be no longer in its portfolio (end of flexible contract, change of aggregator, …).

Payment

The method used for service check, as well as the data source (smart metering data from the DSO) are set as the unique base for the payment from the DSO to aggregators. The contracts describe penalty and potential capped prices for energy formulas.

Impact on energy suppliers and balance responsible parties

The impact on energy suppliers and BRP are of the responsibility of the aggregator which must compensate the electricity supplier consistently to chapter 3.3.6. The BRP of the site are informed by the TSO for each activation. The information is not detailed per site to the BRP in order to protect the aggregator portfolio confidentiality. The TSO is informed by the DSO in order to avoid any impact on the balancing portfolio.

Coordination with the TSO and possibility to stack the value with other mechanisms and markets

The contract reminds the rules set by the regulation in terms of revenue stacking. The coordination with the TSO to manage potential impacts on the transmission system of a DSO flexibility activation is of the responsibility of the DSO.

Impact on prosumers

All risk related to the impact of flexibility activation on customers are part of the service offered by the aggregator who takes full responsibility for it.

4. CONCLUSION

The contract principles described above were designed in the current context in which the value of flexibility at the local level is low and the deployment of electrical storage assets limited.

They do not claim to cover all use cases that may appear in the future. They were designed to be simple and pragmatic.

Contractual complexity should be consistent with the financial stakes. It should grow with the size of the market so as to allow in the short term a sustainable development of it while ensuring the DSO the reliability of the products it contracts for the good operation of its network. With a growing market size the contractual rules should be enriched in order to deal more precisely with the issues left open at first.

This gradual escalation of contractual complexity is essential for the development of services for the benefit of the DSO.