Customer European Commission

Subject Report with detailed policies and measures, objectives and targets in accordance with the Cyprus Integrated National Energy and Climate Plan, as required by Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action, with specific reference to the dimension of the "Internal Energy Market"

Contract REFORM/GA2020/022

Notes Outcome 2 – Output 2.2 – Final version

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REVISIONS HISTORY

Revision number	Date	Protocol	List of modifications and/or modified paragraphs
0	05/01/2021		draft final version
1	09/06/2022	22006065	final version

1 INTRODUCTION

This report is the second deliverable (corresponding to Output 2.2) of:

- Outcome 2 – "Active participation of customers and increase of flexibility in the electricity market and in the power system, in line with the Cypriot Integrated National Energy and Climate Plan"

foreseen by the Grant Agreement:

- Implementation of the EU regulatory framework in the area of electricity in Cyprus.

The goal of the deliverable is to define a:

- Proposal with detailed policies and measures, objectives and targets in accordance with the Cyprus Integrated National Energy and Climate Plan, as required by Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action, with specific reference to the dimension of the "Internal Energy Market".

To this aim, the following documents have been taken as a reference:

- The first deliverable (corresponding to Output 2.1) of Outcome 2 – "Active participation of customers and increase of flexibility in the electricity market and in the power system, in line with the Cypriot Integrated National Energy and Climate Plan" – which is related to "Report on a new policy framework to support and promote flexibility in the electricity system and market";
- The Law for the Regulation of the Electricity Market of 2021.

Possibly, references will be made also to the deliverables results of the following actions carried out by RSE to the benefit of MECI and already financed by the Directorate General for Structural Reform Support (DG REFORM) of the European Commission:

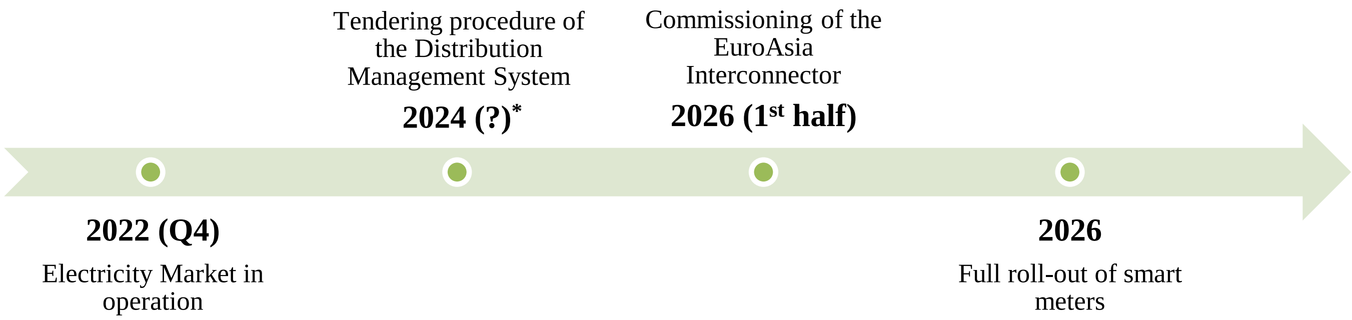
- SRSS/C2016/005 - "Technical and policy/regulation support to the Ministry of Energy, Commerce, Industry and Tourism with regard to its participation in the process for amending the existing Trade and Settlement Electricity Market Rules", carried out in 2016 and in 2017;
- SRSS/S2017/048 - "Technical support to improve the penetration of renewable energy sources and energy efficiency in Cyprus"
    - Work package 1 – "Review and amendment of the Trade and Settlement Electricity Market Rules", carried out in 2018 and in 2019.

The report deals with the following main topics detailed in Output 2.1:

- active customers & renewable self-consumers;
- energy communities;
- incentives for the use of flexibility in distribution networks;
- dynamic electricity price contracts;

- aggregation of distributed resources;
- evolution of ancillary services.

In Figure 1, on the basis of information provided by the Cyprus Authorities, we report the currently expected timeline for the major events that must be taken into account for the purpose of this report, aimed at the implementation in Cyprus of the European framework concerning the electricity market.



* According to info received by EAC on 26/1/2022, it was decided to temporarily postpone the project. The reprogramming will take place in 2 years. During this phase, needs will be met by very small upgrades to the existing transition system.

Figure 1 - Timeline of the main milestones concerning the evolution of the Cyprus electricity market

2 ACTIVE CUSTOMERS & RENEWABLE SELF-CONSUMERS

With reference to what reported in paragraph 4.1 of Output 2.1, our recommendations are the following.

2.1 Ownership of generation plants

As foreseen by the RED II directive concerning “renewables self-consumers”, generation plants might also be owned by a third-party or managed by a third-party for installation, operation, including metering and maintenance, provided that the third-party remains subject to the renewables self-consumer's instructions. The same provision, for coherency, should be applied to active customers, both single and jointly acting, as well as to jointly acting renewables self-consumers.

Moreover, one or more third-party producers should be allowed: in fact, the uniqueness of the third-party producer might be a limit to competition, preventing the self-consumer from developing further production projects devoted to on-site consumption, both by himself and by other producers, different from the one already present. It is therefore appropriate to make possible also a “N to 1” or a “N to M” self-consumption configuration, characterized by N different producers (possibly including the self-consumer(s) itself), dealing with it in the same way as a “1 to 1” or a “1 to M” configuration.

It is also necessary to define how to formalize the concept of “subject to the self-consumer's instructions”: this could be done with the presence of specific clauses in the contract signed by the parties where it is stated that dispatching of the generation plants will be defined by self-consumer(s) or agreed upon between the producer and self-consumer(s).

2.2 Benefits of self-consumption

Self-consumption allows for a reduction of grid losses and, potentially, of network operation and expansion costs (where it reduces the flows on the network and the maximum power required on the connection point), of connection costs and, in theory but not necessarily, of dispatching costs. Therefore, it is appropriate to compensate every self-consumption configuration, independently from the generation source, for the abovementioned avoided costs that it implies for the power system.

This is already done in Cyprus in case of on-site self-consumption, since network fees are applied only on the energy imported from the network, but the Law for the Regulation of the Electricity Market of 2021 allows active customers to operate also “within other premises”, therefore using the public network: in such a case, using the network for production and self-consumption at a certain voltage level (e.g. under the same MV/LV substation), reduces the use of the network at higher voltage levels and the related avoided costs should be compensated.

2.3 Promotion of self-consumption

The best way to promote self-consumption is to provide direct incentives on the self-consumed energy, by possibly differentiating them for each source/generation technology in order to achieve a better calibration.

Moreover, incentivizing the self-consumed energy pushes the self-consumer to change its consumption profile in order to maximize self-consumption itself. This can hardly be done in a “manual” way, requiring tools for energy management. Such maximization can be obtained through:

- storage systems, that moreover are able to provide also additional services (e.g. reduction of imbalances, ancillary services, etc.);
- automation systems for control[1] of loads and of generation (if dispatchable) and, jointly, of storage systems, able to achieve load profiles as much as possible corresponding to generation profiles, as well as to answer to possible requests by an aggregator for the provision of ancillary services.

In this regard, specific support schemes[2] could be defined both for storage systems and for automation systems.

As for the energy that is not self-consumed, the RED II directive states that “renewable self-consumers are entitled to receive a remuneration, including, where applicable, through support schemes, for the self-generated renewable electricity that they feed into the grid, which reflects the market value of that electricity and which may take into account its long-term value to the grid, the environment and society”. Thus, provided that support schemes are already in place for the self-consumed energy, the remaining energy, if it is not sold bilaterally to third parties, might be remunerated at the day-ahead market price.

[1] Both local and remote control, in this latter case for example operated by an independent aggregator.

[2] MECI is in the process of drafting a related Aid Scheme for storage systems downstream the meter, i.e. combined with RES generation. Furthermore, an Aid Scheme for the installation of up to ca. 130 MW-150 MW/2h of storage systems in-front-of-the-meter has been pre-notified to DG Competition. The total budget is €40m to €80m intended to cover the “funding gap”, as defined in the Climate, Energy and Environmental Aid Guidelines (CEEAG).

2.4 Physical versus virtual models

As clearly stated in Output 2.1 a “virtual” collective self-consumption scheme using the public network (see Figure 2) is preferable with respect to a “physical” one (see Figure 3), since every self-consumer remains connected to its POD and, therefore, maintains its rights as final customer, i.e. to freely choose its preferred supplier (possibly different from the suppliers of the other participants to the scheme), as well as to decide not to participate to the collective self-consumption scheme or to get out of it. Moreover, there is no need to install and manage sub-meters in order to determine the bills of each user.

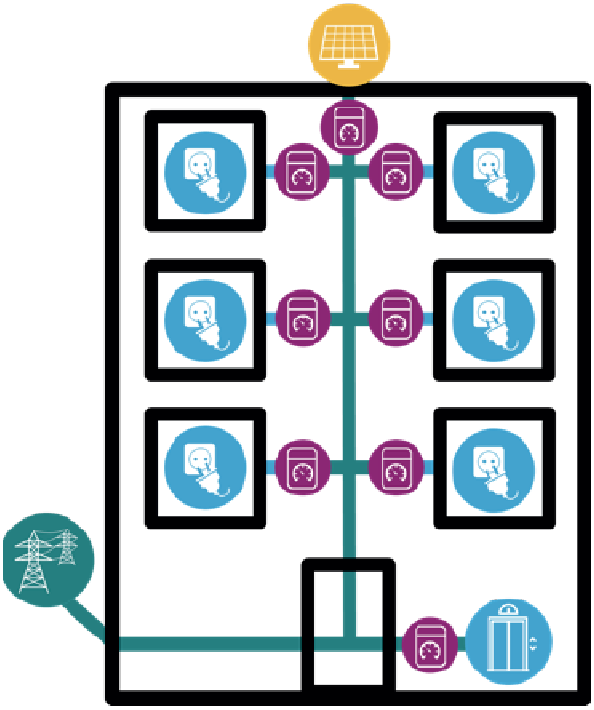


Figure 2 - “Virtual” collective self-consumption scheme

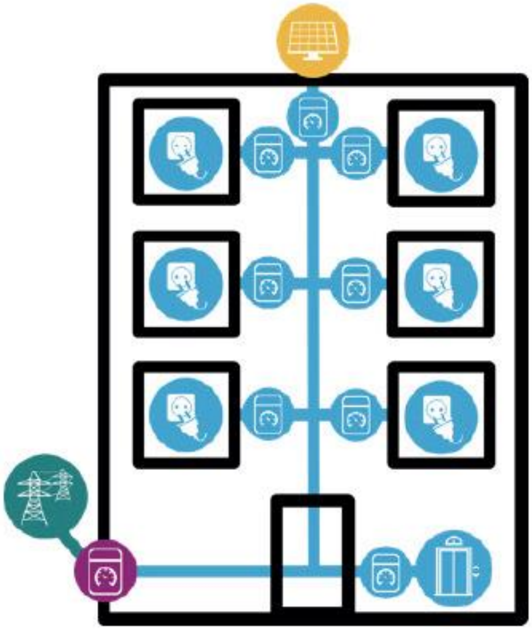


Figure 3 - "Physical" collective self-consumption scheme

In a "virtual" scheme the self-consumed (or "shared") energy is equal to the minimum, in each settlement period (half-hourly smart meters are progressively being deployed in Cyprus), between the energy produced and injected into the network by the generation plants and the energy withdrawn from the network by all the customers participating to the scheme.

Moreover, the measurements taken in each POD allow to attribute to each customer its share of self-consumed energy, on the basis of criteria freely defined among the participants to the collective self-consumption scheme (for example, proportionally to the consumption of each user in each measurement time interval).

3 ENERGY COMMUNITIES

With reference to what reported in paragraph 4.2 of Output 2.1, our recommendations are the following.

3.1 Participation to energy communities and rights of members

The IEM and RED II directives are quite clear about the membership and effective control criteria of Citizen Energy Communities (CECs) and of Renewable Energy Communities (RECs), summarized in Figure 4.

Moreover, the RED II directive introduces for RECs also the concept of "autonomy" with respect to its members private interests. This means that the governance model must ensure that each member is adequately represented and that a minority of members should not have the power to impose their will to the whole community. This could be obtained for example by imposing a cap on voting rights or even to apply the principle of one member – one vote. In this regard, several different approaches can be adopted; for example, as recalled in Output 2.1:

- the Greek Energy Communities framework limits the financial participation of members to 20% of the community capital, except for local authorities which are limited to 40% of the community capital if located on the mainland, and to 50% of the community capital for islanded municipalities of less than 3500 inhabitants,
- in Germany, no individual member of "Citizens' Energy Companies" can hold more than 10% of voting rights,
- in the Netherlands and in Belgium there are examples of energy communities that apply the principle of one member – one vote,
- in Lithuania, at least five members must be natural persons, holding a minimum of 51% of all votes.

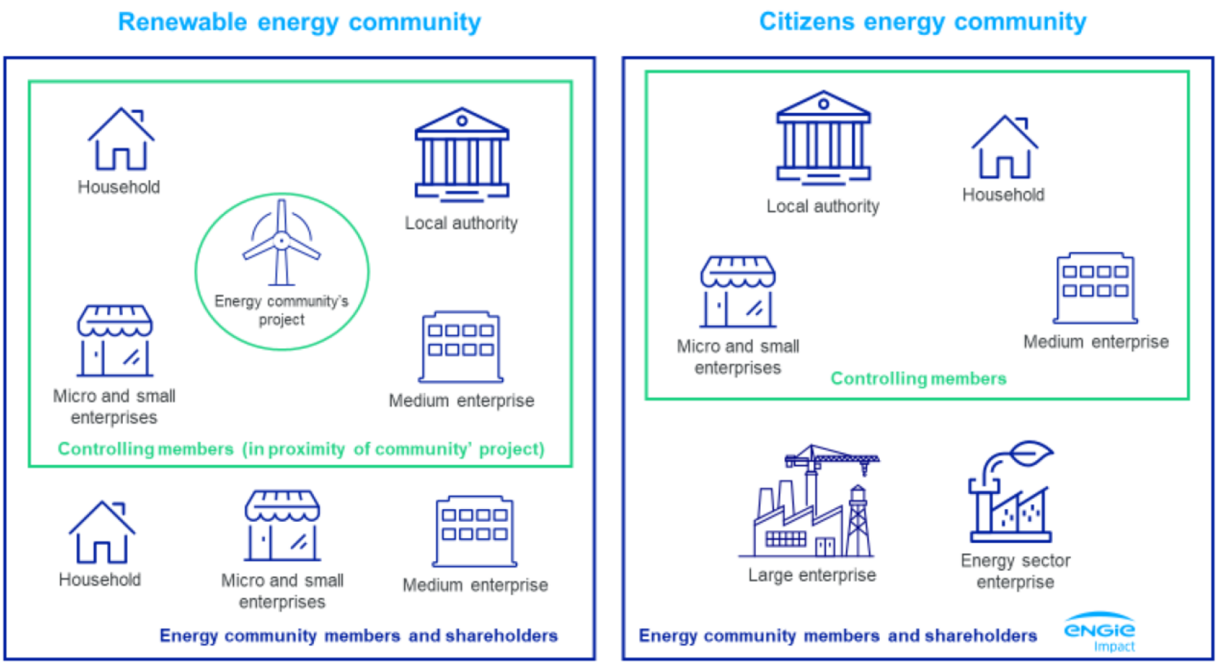


Figure 4 - Membership and effective control criteria of RECs and CECs (source: European Commission - ASSET Study on Energy Communities in the Clean Energy Package: Best Practices and Recommendations for Implementation)

Moreover, the IEM directive explicitly specifies that the shareholders or members of a CEC have the right to quit the community and they keep their rights and obligations as final customers and as active customers. In case of leaving the community, what is foreseen by Article 12 of the IEM directive on change of supplier applies, with a possible payment of a fee. In principle, the same should apply to RECs (even if this issue is not explicitly mentioned in the RED II directive) and the exact conditions for leaving can be established in the statutes of the communities.

Generally speaking, RECs must comply with more stringent criteria with respect to CECs. The compensation for the more stringent criteria is the possibility for RECs to access support schemes, explicitly mentioned in the RED II directive, but never mentioned (while not explicitly excluded) in the IEM directive concerning CECs. Since it seems opportune to promote the development not only of renewable sources, but also of natural gas High Efficiency Cogeneration – HEC, CECs that access support schemes for HEC might be requested, in terms of minimum requisites for the access, the same characteristics requested for the RECs (i.e. participation limited to natural persons, local authorities, including municipalities, or SMEs, whose participation must not be the main commercial or professional activity and with decision-making powers reserved to the members of such categories located in the proximity of the plants of the community).

3.2 Ownership of generation plants

In line with what foreseen for individual and collective self-consumption (see paragraph 2.1), we deem that the energy[3] generation plants at the service of a community, besides being property of the community itself, may also be property of and managed by third-parties, even different from each other (typically, they cannot be members of the community, since their participation would be their main commercial or professional activity).

It should be advisable to define some specific criteria to better ensure the “instruction and control” power of the community towards the third parties having the property or managing the plants owned by the community. Just like in the case of individual and collective self-consumption, this could be done with the presence of specific clauses in the contract signed by the parties where it is stated that dispatching of the generation plants will be defined by the community or agreed upon between the producer and the community.

3.3 Activities carried out by energy communities

The set of activities that an energy community can carry out is defined in a more detailed manner by the IEM directive for CECs: in particular, they “may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders”. We assume that the same is possible for RECs.

As for the possible role of DSO that a community can play, according to Article 123 of the Cyprus Law for the Regulation of the Electricity Market of 2021, Citizen Energy Communities have the right to own, set up, purchase or lease distribution networks and to operate them autonomously. In this regard, we suggest not to promote / incentivize this option unless in case specific technical reasons justify it, taking into account the cost-benefit ratio for final customers. In fact, in addition to avoiding a possible duplication of infrastructures, DSOs have more structured technical competences to manage the network and, most important, can benefit of larger economies of scale than the communities, with resulting greater efficiencies.

This is the reason why, just like in case of collective self-consumption (see paragraph 0), we suggest the “virtual” scheme using the public distribution network as the best implementation option also for energy communities.

[3] In principle not only electric energy, but also thermal energy, in case of a REC.

Moreover, the RED II directive requires that "the relevant distribution system operator cooperates with Renewable Energy Communities to facilitate energy transfers within Renewable Energy Communities". The IEM directive, on the other hand, requires that "subject to fair compensation as assessed by the regulatory authority, relevant distribution system operators cooperate with Citizen Energy Communities to facilitate electricity transfers within Citizen Energy Communities". This role of the DSO should be enforced in the regulatory framework.

Finally, it must be noted that while the CECs defined by the IEM directive deal with electric energy, the RECs defined by the RED II directive deal with renewable energy in general, therefore also with thermal energy. It is therefore opportune to allow energy communities also to produce (with renewable or High Efficiency Cogeneration plants), distribute (with district heating / cooling networks) and supply thermal energy to their members and to the local communities.

3.4 Exchange / sharing of energy within the community

Even if the RED II directive specifies that the RECs have the right to share within the community the renewable energy produced by the generation plants owned by the community and, similarly, the IEM directive states that the CECs are entitled to arrange within them the sharing of electricity that is produced by the production units owned by the community, implying that the flow of the shared energy always goes from the plants owned by the community towards its members, we support the position that single members of the community may share (just in their role of members, and not being simple self-consumers that would sell their excess production to the community) with the other members energy produced by their own plants.

Moreover, "sharing" of energy among community members should not be considered the same as "supplying" of energy, therefore fiscal charges should not be paid on the shared energy: this would be an additional element of promotion for energy communities.

3.5 Extent of energy communities

As already highlighted in Output 2.1, the concept of "locality" for a CEC or of "proximity" to the plants of the RECs of the members with decision-making powers might be interpreted as a "physical" proximity (to be defined, e.g. within X kilometers), an "administrative" proximity (e.g. in the same municipality, since local authorities can be shareholders or members of a community) or even an "electric" proximity (for example a community with all the injection and withdrawal points connected under the same secondary or primary substation). All such three criteria are currently adopted in different European countries.

If, on one hand, defining a precise "electric" extent would facilitate the assessment of the avoided costs for the system deriving from the energy sharing carried out within the community, on the other hand it might not be completely coherent with the social / territorial context where the community should develop. The social / territorial extent appears to be of prevailing importance, since the main aim of the communities, as explicitly established by the directives, is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits. In fact, the IEM directive, dealing with the experiences already made in cases similar to energy communities, states that: "Where they have been successfully operated such initiatives have delivered economic, social and environmental benefits to the community that go beyond the mere benefits derived from the provision of energy services".

Thus, among the "physical", "administrative" or "electric" extents, the "administrative" ones seem to be the most adequate to the concept of energy community: for example, one or more neighboring municipalities, a province, etc.

In any case, a combination of the abovementioned kinds of constraints might be envisaged. Moreover, constraints should be defined considering the variety of the characteristics of the territories where communities might be established (e.g. urban vs. rural vs. mountain areas, population density, natural resources, etc.).

The Cyprus Authorities, on the basis of their deep knowledge of the administrative, social and territorial contexts, as well as of the "electrical" ones, may select the optimal option on the basis of the aforementioned general principles.

3.6 Imbalances

The IEM directive explicitly foresees that CECs "are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943".

The RED II directive does not contain any explicit provision concerning imbalances, but it is reasonable to assume that also RECs should be subject to the same rule that applies to CECs, in line with Regulation (EU) 2019/943.

Therefore, all energy communities shall either be balance responsible parties or shall contractually delegate their responsibility to a balance responsible party of their choice.

This is quite clear when a community operates a private network and is the only supplier of its members, thus being considered a sort of black-box connected to the public network. On the other hand, in the "virtual" model that we deem preferable, where energy is shared within the community using the public network, the community (or a delegated third party) would be responsible for the imbalances caused by its generation plants and each member will have its supplier as a BRP, therefore the usual imbalance regulation can be applied.

3.7 Benefits and promotion of energy communities

Just like in the similar case of collective self-consumption (see paragraph 2.3) the best way to promote energy communities is to provide direct incentives on the "shared" / self-consumed energy, by possibly differentiating them for each source/generation technology in order to achieve a better calibration.
Moreover, incentivizing the "shared" energy pushes the members of the communities to change their consumption profile in order to maximize self-consumption. Again, this requires energy management tools, such as storage systems and automation systems to optimize energy flows over time, that may benefit from specific support schemes.
In addition, the avoided network-related costs should be discounted from the tariff fees paid by the members of the community.
When defining and calibrating support schemes for the development of energy communities, it would be opportune to take into account not only the energy-related aspects ("shared" energy), but also the economic, social and environmental benefits not only for the members of the communities, but also for the whole territory where they operate, possibly providing for such aspects additional rewards or support.
In this regard, a very important issue that can be tackled by energy communities is energy poverty. In fact, Article 22 of the RED II directive states that Member States shall provide an enabling framework that shall ensure that the participation in the Renewable Energy Communities is accessible to all consumers, including those in low-income or vulnerable households. In fact, the self-production of energy by the community and the possibility of sharing it at a lower cost than the market and the possibility for the community to promote energy efficiency interventions, thus reducing energy consumption, are key factors to reduce the bill of energy-poor consumers.

Therefore, the possibility of defining specific Key Performance Indicators – KPI to quantify such categories of benefits[4], on the basis of which to quantify possible additional rewards or support (paying attention not to overlap with other existing support schemes), should be taken into account.

[4] For example, reduction of local NOx emissions achieved by the community due to the electrification of end uses, number of families no longer in condition of energy poverty among the members of the community, number of charging points for electric vehicles installed by the community, reduction of consumption / emissions due to energy efficiency interventions, etc.

4 INCENTIVES FOR THE USE OF FLEXIBILITY IN DISTRIBUTION NETWORKS

Article 32 - *Incentives for the use of flexibility in distribution networks* of the IEM directive specifies that "Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services". Such services should not only "support the efficient and secure operation of the distribution system" but should also "cost-effectively alleviate the need to upgrade or replace electricity capacity". In fact, the same article specifies that DSOs' network development plans "shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the DSO is to use as an alternative to system expansion". Moreover, DSOs "shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion".

In fact, one of the main issues concerning the procurement of flexibility services to the benefit of the distribution network is whether a truly competitive market could be established, since typically the problems to be solved in the network, such as congestions or anomalous voltage profiles, have a strictly local nature and therefore few resources can compete to provide the required flexibility services. If a competitive market cannot be established, a regulated remuneration for the provision of such services might be put in place.

Moreover, the DSO should be incentivized to procure flexibility services as an alternative to network expansion: in practice, it should be rewarded not only to allow the recovery of the costs related to the purchase of the services, but also taking into account to some extent the avoided costs of network expansion. In other words, the possible cost savings of using flexibility services instead of expanding the network should be shared between the system and the DSO. In addition, it would be desirable that, in the network development plan, when proposing a network expansion project, the DSO justifies why using flexibility services is not a viable or convenient alternative.

It has been asked by MECI what is, in this context, the possible role of energy communities owning and operating their distribution network: in such a case they are considered Distribution System Operators and are subject to all regulations that apply to DSOs, therefore there are no peculiarities for them, as far as demand of flexibility services is concerned.

On the other hand a community can be a provider of flexibility services for the distribution network to which its network is connected, for the public distribution network to which their members and their plants are connected, in case of a "virtual" scheme, and for the transmission network.

In fact, flexibility services by Distributed Energy Resources are precious not only for the DSO, but also for the TSO, in order to ensure the secure operation of the whole system. In this regard, article 32 of the IEM directive states also that “Distribution system operators shall exchange all necessary information and shall coordinate with transmission system operators in order to ensure the optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development”.

The different coordination schemes, which have been described in Output 2.1, have different characteristics (see Table 1), as well as specific benefits and attention points (see Table 2) related to the TSO grid operation, the DSO grid operation, other market participants involved and the market operation in general. We briefly recall here how the five coordination schemes work:

- **Centralized AS market model**: the TSO contracts services directly from DER. No congestion management is carried out for distribution grids.
- **Local AS market model**: the DSO manages a local congestion market. Unused resources are transferred to the AS market managed by the TSO (procuring balancing and congestion management services for the transmission network).
- **Shared Balancing Responsibility model**: the TSO transfers to the DSO balancing responsibility for the distribution grid. The DSO manages a local congestion and balancing market using local DER.
- **Common TSO-DSO AS market model**: the TSO and the DSO manage together a common market (balancing and congestion management) for the whole system.
- **Integrated Flexibility market model**: TSOs, DSOs and market players contract DER in a common flexibility market.

As shown by the Horizon 2020 SmartNet project, coordinated by RSE, the choice of the appropriate coordination scheme is dependent on multiple factors such as the type of ancillary service, normal operation versus emergency situations, the state of the grid, the amount of RES installed, the current market design and the regulatory framework. Moreover, the choice for a specific coordination scheme does not imply that this scheme could never be adapted. Across coordination schemes, there is a gradual increase of the role and responsibilities of the DSO. Dependent on the national evolution, a country can evolve from one coordination scheme to another.

In particular, the Centralized AS market model, the Common TSO-DSO AS market model (centralized variant) and the Integrated flexibility market model share a common market architecture in terms of market platform and ICT requirements. A shift between these coordination schemes is mainly a question of a change in roles and responsibilities. The Shared balancing responsibility model could be seen as a duplication of the same market architecture as well. Also, the Local AS market model and the Common TSO-DSO AS market model (decentralized variant) share a common market architecture.

Table 1 - Comparison of the key elements of the five coordination schemes.

Coordination scheme	Role of the DSO	Market organization (market operator)	Allocation principle of flexibility from the distribution grid
Centralized AS market model	Limited to possible process of prequalification	Common market (TSO)	Priority for the TSO
Local AS market model	Organization of local market Buyer of flexibility for local congestion management Aggregation of resources to central market	Central market (TSO) Local market (DSO)	Priority for the DSO
Shared Balancing Responsibility model	Organization of local market Buyer of flexibility for local congestion management and balancing	Central market (TSO) Local market (DSO)	Exclusive use for the DSO
Common TSO-DSO AS market model	Organization of flexibility market in cooperation with TSO Buyer of flexibility for local congestion management	Common market (TSO and DSO) Central market (TSO) Local market (DSO)	Minimization of total costs of TSO and DSO
Integrated Flexibility market model	Buyer of flexibility for local congestion management	Common market (Independent Market Operator)	Highest willingness to pay

The feasibility of the implementation of each coordination scheme is very dependent upon the regulatory framework. The Centralized AS market model is the most in line with current regulations. The other coordination schemes would require considerable changes with respect to roles and responsibilities of TSOs and DSOs. The implementation of a coordination scheme is also influenced by the national organization of TSOs and DSOs, e.g. the number of system operators (both TSOs and DSOs) and the way they currently interact.

In addition, the implementation of certain coordination schemes will have an impact on other markets, such as the Intraday markets. Dependent on the services offered in the AS market, and compared to the Intraday markets (IDM), these markets might be able to co-exist or alternatively, may need to be integrated. Although TSO-DSO coordination could be organized on a country level, it is important to integrate national TSO-DSO coordination set-ups within the process of EU harmonization and integration.

Summarizing, the main findings of the SmartNet project are the following:

1. Traditional TSO-centric schemes could stay optimal if distribution networks don't show significant congestion not unlikely in near-future scenarios, since distribution grid planning was (and still is) affected by the fit-and-forget reinforcements policy. In a first period, costs to implement monitoring and control systems within distribution networks could result higher than the effect of over-investments inefficiencies due to the old fit-and-forget philosophy. This could engender resistance in some DSOs to consider flexibility as a value. This could also call for a

revision of present remuneration schemes for DSOs' investments, so that they can claim OPEX and not only CAPEX[5,6].

2. More advanced centralized schemes incorporating distribution constraints show higher economic performances, but their performance could be undermined by big forecasting errors, which could bring them to take wrong decisions. As distributed generation, constituting a good share of the possible services providers in distribution, is mainly composed by RES generation (e.g. PV power plants, mini-hydro ...) it is important that the gate closure is shifted as much as possible toward real time and forecasting techniques are improved. Such techniques can be better for some generation technologies (PV) but much worse for others which are strongly influenced by local factors.
3. Technical reasons and high ICT costs dis-advise to give balancing responsibility to DSOs. Nonetheless, the sheer economic performance of such shared responsibility schemes is not always bad (sometimes separating transmission and distribution markets could prevent high prices in one area to be spread to the other).
4. Decentralized schemes are usually less efficient than centralized ones because the two-step process introduces undue rigidities. Scarcity of liquidity and potential impact of local market

[5] For example, the report *"Optimal regulation for European DSOs to 2025 and beyond"* by CERRE states that TOTEX incentive regulation in Great Britain, which allows both OPEX and CAPEX savings to be rewarded, has encouraged flexibility service procurement to reduce capital investment requirements. See https://cerre.eu/wp-content/uploads/2021/04/CERRE_Optimal-regulation-for-European-DSOs-to-2025-and-beyond_April-2021_FINAL.pdf

[6] MECI reported the following part of the «Statement of regulatory practice and pricing methodology» in force in Cyprus: *"Pricing methodologies reflect fixed costs for transmission and distribution system operators and provide them with appropriate incentives, both short-term and long-term, to increase efficiency, including energy efficiency, promote market integration and security of supply, research and related research activities, and to facilitate innovation in the interests of consumers in areas such as digitization, flexibility services and interconnection"*. Apparently OPEX are not mentioned as a relevant element for the procurement of flexibility services. In this regard, EDSO for Smart Grids in its "Response to CEER consultation on incentives schemes for regulating DSOs, including for innovation" suggests including incentives for OPEX in order to reflect the growing needs for OPEX related to flexibility in distribution networks. In particular, it is stated that: *"Moreover, as grid extension implies investments (CAPEX) the implementation of smart grids may increase the weight of OPEX in distribution costs. This effect becomes even more critical if smart grids demand that investments should be replaced more frequently by OPEX e.g. for the use of contracted flexibility at the distribution level. Regulation should therefore incentivise DSOs to reach the most efficient outcome by accounting both for the changing OPEX and CAPEX structures."* See https://www.edsoforsmartgrids.eu/wp-content/uploads/170512-CEER-consultation-DSO-incentives-and-innovation_FINAL_clean-version-updated-002.pdf

power, along with extra constraints introduced to avoid counteracting actions between local congestion market and balancing market (e.g. increasing system imbalance while solving local congestion) furthermore negatively affect economic efficiency of decentralized schemes.

5. Decentralized schemes request to put in place further coordination actions between TSO and DSO: resources which are bid in both sequenced markets should not be selected twice (a "common marketplace" mechanism should be implemented).
6. Local congestion markets should have a "reasonable" size and guarantee a sufficient number of actors are in competition in order to prevent scarcity of liquidity and exercise of local market power. For that, small DSOs should pool-up in order to create a common congestion management market: too many small local markets would increase ICT costs and reduce competition, with detrimental effects.
7. Intraday markets should bring gate closure as close as possible to real time. However, it is not feasible to overlap a real-time session of intra-day market with a services market: this solution would create uncertainty in the operators (TSO and DSO) in charge of purchasing network services because they would be no longer sure of how many resources are needed (i.e. the real amount of congestion and imbalance). For this reason, this coordination scheme is strongly dis-advised.
8. Balancing and congestion markets should have as target not to optimize system social welfare (that is, by contrast, the goal of energy markets) but just to buy the minimum amount of resources to get the needed network services while perturbing the least possible the results of the energy markets. This advises against allowing the award of sets of balanced upward and downward bids just to reduce total costs ("market arbitrage") even whenever this could reduce total system costs.
9. Ensuring level playing field in the participation of distributed resources (especially industrial loads) to the tertiary market means to be able to incorporate into the market products some peculiarities of such resources (loads or generators) without which it is nearly impossible for them to participate. This could imply to enable complex bids or other sophisticated products.
10. Reaction to commands coming from TSO or DSO in real time of the control loops which were initially planned for real time services provision can be too slow. So, a testing is needed to ensure compatibility with requested reaction times.
11. ICT is nearly never an issue: whatsoever TSO-DSO coordination scheme is implemented, the economic performance depends by wide and large on operational costs. For all coordination schemes, ICT costs stay one order of magnitude lower than operational costs.

Besides, the main benefits and attention points for each scheme for the different stakeholders are shown in Table 2 below.

Table 2 - Main benefits and attention points for each scheme for the different stakeholders.

Domain	**Performance Criteria**	**Coordination scheme**				
		Centralized AS market model	**Local AS market model**	**Shared Balancing Responsibility model**	**Common TSO-DSO AS market model**	**Integrated Flexibility market model**
Interaction between system operators	Adequacy of existing communication channels, including the use of common data	High	Medium	Medium	Low	Medium
Grid operation	Respecting distribution grid constraints	Low	High	High	High	High
	Use of resources from the distribution grid by the TSO	High	Medium	Low	High	High
	Recognition of the evolving role of the DSO	Low	High	High	High	High
Market operation	Possibility to lower market operation costs	High	Low	Low	Medium	Medium
	Liquidity of the market	Medium	Low	Low	Medium	High
	Economies of scale	Medium	Low	Low	High	High

Therefore, taking into account the above-mentioned analysis, the centralized ancillary services market model is deemed preferable for a small system like Cyprus that is in the initial phase of electricity market operation, being it the easiest model to manage and to implement, starting from the current framework that foresees a central dispatch system with an Integrated Scheduling Process and a related ancillary services market managed by the TSO.

In this phase it is important to give priority to the implementation of this market design by focusing on the system-wide needs and the provision of services to the TSO, therefore the role of the DSO in this context might be initially limited to the pre-qualification of distributed resources for the provision of such system-wide services.

As the system, with an increasing penetration of distributed renewable sources, will evolve and the need for local flexibility services at the distribution level will become significant, a more complex TSO-DSO coordination scheme with a more active role of the DSO will have to be taken into account.

5 DYNAMIC ELECTRICITY PRICE CONTRACTS

The IEM directive in Article 11 states that *"Member States shall ensure that the national regulatory framework enables suppliers to offer dynamic electricity price contracts. Member States shall ensure that final customers who have a smart meter installed can request to conclude a dynamic electricity price contract with at least one supplier and with every supplier that has more than 200 000 final customers."*
A dynamic electricity price contract is defined by the directive as "*an electricity supply contract between a supplier and a final customer that reflects the price variation in the spot markets, including in the day-ahead and intraday markets, at intervals at least equal to the market settlement frequency*".
Thus, they are designed to send scarcity price signals about the matching of supply and demand on the wholesale market (at system level, due to system marginal price), independently from the scarcity or the criticalities that may occur locally in the distribution network.
A pre-requisite for the application of dynamic electricity price contracts is the availability of smart meters: according to Figure 1, the roll-out of smart meters in Cyprus should be completed by June 2026. Of course, such contracts might be made available to the final customers already equipped with a smart meter even before the completion of the roll-out. In any case, as stated by the directive, Member States shall ensure that final customers are fully informed by the suppliers of the opportunities, costs and risks of such dynamic electricity price contracts, and shall ensure that suppliers are required to provide information to the final customers accordingly, Moreover, suppliers shall obtain each final customer's consent before that customer is switched to a dynamic electricity price contract.
For the application of these provisions there is no specific derogation foreseen for Cyprus in the IEM directive.
The convenience of a dynamic price contract for a consumer, in contrast with a fixed-price one, for a specific reference period (e.g. one year), basically depends on the combination of two factors:

- the future market conditions:
    - in case of declining spot prices in the reference period, of course the dynamic price contract will show average prices lower than the fixed-price one;
    - in case of stable spot prices in the reference period, the dynamic price contract will still show average prices lower than the fixed-price one, since the supplier will not have to charge the consumer with the hedging costs that characterize the fixed-price contract, but not the dynamic price one;
    - in case of rising spot prices, of course the hedging characteristics of fixed-price contracts will show their benefits over the dynamic price ones, with the consumer completely exposed to the price increase;
- the shape of the consumer load profile, as well as his/her possibility of changing it in order to concentrate consumptions in periods when spot prices are lower (in principle, even if the average

spot price is higher than the price of a fixed-price contract, a load profile concentrated in hours when spot prices are lower might still allow savings).

Thus, it is not possible to make a general statement about the superiority of dynamic vs. fixed-price contracts or the other way around, since it depends case-by-case and also on the risk aversion of the consumer. In any case, as stated by the IEM directive, it is very important that, before signing a dynamic price contract, consumers are fully aware of the factors that can affect the convenience of such contracts and receive all the necessary information.
In this regard, as reported in Output 2.1, we fully agree with the following recommendations by CEER:

- inform consumers that the reference spot price is subject to a wide range of variation over time, within the year and from one year to another; in this regard, consumers should be informed of the typical shape of spot price profile (possibly differentiated for type of day, season, etc.) so that they are aware of the lowest-price hours when it is advisable to concentrate consumption and of the highest-price hours when consumption should be reduced as much as possible;
- provide customers with an estimate of the magnitude (maximum/minimum) of past dynamic prices that a consumer would have paid per month / per year, etc., based on his/her consumption profile over the previous year, if such data is available to the supplier, and the prices recorded historically over a long period of time (typically 5 years minimum). If such historic consumption data is not available to the consumer, an average consumption profile could be used. Even then, the customer should be informed that the price may still exceed these limits in the future;
- if actual customer consumption data is not available, then the supplier should provide access to a tool that would enable consumers to predict their approximate consumption profile, depending on property type, number of occupants (including children), equipments owned, consumption characteristics, etc., in order to better estimate the suitability of the dynamic price contract for them;
- inform consumers of the importance of managing consumption in order to prevent potential bill increases, and that automation devices could be useful in this regard.

In order to provide clarity to customers, information on consumption levels and reference prices could be provided at an aggregated time interval on the main billing document, such as using daily or weekly averages. The essential information for the consumer for the average time interval period is the level of consumption and the price average over the period weighted by the consumption. Moreover, billing information should be provided on a frequent basis, at most monthly. If the customer requires further information, the supplier must provide them free access to a data repository and adequate reporting tools, so that they can analyse their actual consumption and the prices charged at time intervals at least equal to the market settlement frequency.

In addition, since the wholesale reference price is the same across suppliers, they will compete on the basis of the price add-on that reflects suppliers' operational costs and profit margin. According to CEER, the impact of these add-ons on the final price of a dynamic price contract (e.g. structure, magnitude, etc.) should be made clear to the customers when they choose a supply contract, as this is one of the most relevant parameters they will use to compare suppliers, taking also into account that comparison tools will not be able to compare fixed price contracts, where the price is known beforehand, with dynamic ones, that are based on future prices that should be predicted.

As discussed in Output 2.1, in addition to dynamic electricity price contracts, there is the possibility of applying dynamic network tariffs. It is worth highlighting that – as also shown in the report of the Council of European Energy Regulators - CEER on electricity distribution tariffs supporting the energy transition[7] – a dynamic network tariff should not be confused with the dynamic electricity price contracts envisaged by the IEM directive or with other forms of valuing flexibility, because they provide a completely different price signal, related to short-term needs concerning grid operation and/or long-term needs concerning network development.

In this regard, if, on one side, dynamic network tariffs can promote a more efficient use of the network allowing to postpone reinforcements and the related costs, on the other side, as discussed in Output 2.1, they in general may imply significant complexities both for the DSO, in terms of defining the timing of the price signals and the estimation of long-term avoided costs, and for the regulatory authority, in terms of tariff design and of cost distribution among final customers. The necessity of the availability of automation systems to allow customers to effectively respond to price signals is instead common to both dynamic electricity price contracts and to dynamic network tariffs.

In any case, it is possible to set up dynamic network tariffs that do not imply a significant burden for their implementation. An example of this is the initiative of the Italian regulatory authority ARERA to promote smart charging of electric vehicles in households (resolution no. 541/2020/R/eel). In particular, the main requisite is the availability of a charging device (e.g. a "wallbox") able to:

- measure and register the active power supplied to the electric vehicle and to transmit such measurement to a third party designated by the customer (e.g. an "aggregator");
- receive and execute commands issued by such third party to:
    - reduce the maximum charging power;

[7] Council of European Energy Regulators – CEER: *Paper on electricity distribution tariffs supporting the energy transition*, Ref: C19-DS-55-04, 20 April 2020. https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0

- increase or restore the maximum charging power[8].

A customer equipped with such a charging device and having a contractual power of 2 to 4.5 kW[9], as well as a first or second generation smart meter, in the hours from 23:00 to 7:00 of the days from Monday to Saturday and in all the hours of Sundays and holidays will have its contractual power increased to 6 kW at no cost (i.e. with no increase of the €/kW tariff component).

In this way, the use of the network in hours when it is typically lightly loaded is promoted, thus postponing the need for reinforcements. Moreover, the diffusion of "smart" charging devices is promoted as well, allowing them to provide ancillary services, both at the local and at the global level, through aggregation.

In conclusion, especially in the initial phase of electricity market operation in Cyprus, when moreover the roll-out of smart meters will be far from its completion, it is not advisable to introduce additional complexities by applying time-differentiated static or even dynamic network tariffs. Nevertheless, as market evolves, a cost-benefit analysis of their introduction might be worthwhile, starting from simple schemes like the Italian one above described.

[8] The list of charging devices compliant with such specifications is reported on the website of Gestore Servizi Energetici – GSE, the parent company of RSE (https://www.gse.it/servizi-per-te/rinnovabili-per-i-trasporti/agevolazioni-per-la-ricarica-dei-veicoli-elettrici/elenco-dispositivi).

[9] The typical contractual power of an Italian household is 3 kW.

6 AGGREGATION OF DISTRIBUTED RESOURCES

The IEM directive defines the role of *"independent aggregator"* as *"a market participant engaged in aggregation who is not affiliated to the customer's supplier"*. Article 13 of the directive states that *"Member States shall ensure that, where a final customer wishes to conclude an aggregation contract, the final customer is entitled to do so without the consent of the final customer's electricity undertakings"*, while article 17 states that the regulatory framework of each Member State shall ensure *"the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants"*. Consequently, the Law for the Regulation of the Electricity Market of 2021 foresees the role of *"independent aggregator"*, too.
Thus, even if the new regulatory framework should allow for independent aggregators, in the initial phase of the liberalized market operation in Cyprus most probably there will be few suppliers and even fewer potential independent aggregators, therefore the so-called "Integrated Model" discussed in Output 2.1, where Supplier and Aggregator coincide, should be allowed, since it is the most straightforward and simple to implement.

The main features of the "Integrated Model" are described below.

<u>*Involved market roles*</u>

- *Prosumer / Active Customer*. It represents the end user that no longer only withdraws energy from the grid, but also injects energy. The key figure is a residential and a small, medium or large-sized commercial/industrial customer.
- *Supplier*. The main task is to procure, supply and invoice energy to its customers (residential, commercial, industrial). In particular, the Supplier and its customers agree on commercial terms for the procurement and supply of energy.
- *Aggregator*. The main role is to collect flexibility from prosumers and their ADSs[10] and sell it as explicit flexibility services to flexibility requesting parties, by optimizing the economic value of the flexibility in its portfolio.
- *Balance Responsible Party*. It is responsible for balancing supply and demand for its portfolio; the portfolio may consist of producers, aggregators and prosumers; besides the BRP acts as a Flexibility Service Provider to the System Operator (TSO/DSO).

[10] Active Demand & Supply (ADS) represents all types of system devices that either demand energy or supply energy and which can be actively controlled. In particular, the controllable ADS device enables to respond to signals by network/market operators (e.g. price signals, network signals, other signals by the aggregator) and to provide flexibility to the energy markets and/or to network operators via the aggregator.

- *Distribution System Operator*. It is responsible for the management of the distribution grid.
- *Transmission System Operator*. It is responsible for the management of the transmission grid.
- *Metered Data Responsible*. It is responsible for the establishment and validation of measured data. Based on the experiences of the European countries, this role can be performed by the existing DSO. The MDR plays a role in the flexibility settlement process and in the wholesale settlement process.
- *Imbalance Settlement Responsible*. It is responsible, for the TSO's scheduling area (e.g. a bidding zone), for establishing and communicating the realized consumption and production volumes per Imbalance Settlement Period and to settle the corresponding imbalances.

Implementation of the aggregator role

Supplier and Aggregator roles are combined in one market party.

Contractual relationships

The Supplier and Aggregator roles are combined in one market party (Supplier-Aggregator) therefore there is no need for a specific contractual relationship between them. Besides, the Supplier-Aggregator has a contractual relationship with the Prosumer / Active Customer, selling energy to it (with a Supply Contract) and buying flexibility from it (with a Flexibility Purchase Contract). The combined balance responsibility is contracted by the Supplier-Aggregator with the associated BRP so that its balance position is ensured by the BRP. The Prosumer owns the devices and delegates responsibility for controlling its flexibility to the Supplier-Aggregator. The final flexibility provision to the TSO/DSO[11] can be contracted (i.e. with an Ancillary Service Contract or Flexibility Service Contract) between the Supplier-Aggregator[12] and the TSO/DSO.

Information flows

Basically, the flexibility service trading involves three main information flows, related to the energy supply between the Supplier-Aggregator and the Active Customer, the flexibility purchase between the Supplier-Aggregator and the Active Customer and the flexibility trade between the Supplier-Aggregator and the Flexibility Requesting Party (TSO, DSO and possibly BRPs). These main information flows are implemented in the following phases:

[11] Or even to a BRP that needs it to balance its portfolio.

[12] The USEF Integrated Model takes into account the possibility that the BRP of the Supplier-Aggregator plays the role of Balancing Service Provider, acting as an intermediary between the Supplier-Aggregator and the TSO/DSO.

- *Contract* – The Supplier-Aggregator signs contracts with the Active Customer (energy supply/flexibility purchase contracts); moreover, the Active Customer sign a contract with the DSO (connection contract), as well as with the Metered Data Responsible (metering contract), that usually is the DSO;
- *Plan and Validate* – It is the process of requesting, offering and ordering flexibility services that takes place between the Supplier-Aggregator and the Flexibility Requesting Party (TSO/DSO/BRPs), as well as the communication of the nomination (baseline of default profile) from the BRP contracted by the Supplier-Aggregator to the Imbalance Settlement Responsible;
- *Operate* – The Supplier-Aggregator receives the “flex” order (command sent by the Flexibility Requesting Party) to activate the flexibility service contracted. The Supplier-Aggregator has the freedom to choose from all the flexible assets in its portfolio the best set to meet the required volume, including the possibility to reschedule them, if needed. Besides, the Flexibility Requesting Party can require the provision of real-time measurement data, typically at portfolio level;
- *Settle* – The Flexibility Requesting Party (TSO/DSO/BRPs) settles the Supplier-Aggregator for the provision of flexibility services; to this end the Metered Data Responsible provides meter data related to the activated flexibility to the Flexibility Requesting Party in order for it to quantify the flexibility service and communicate to the Supplier-Aggregator the flexibility settlement (the Supplier-Aggregator needs to receive the meter data related to its flexibility activation, too).

Flexibility Services

The explicit flexibility services offered by the Supplier-Aggregator include:

- wholesale services;
- constraint management services;
- balancing services;
- adequacy services.

Wholesale services help BRPs to decrease procuring costs (purchase of electricity) mainly on Day-Ahead and Intraday markets; in particular, the flexibility provided by the assets of Active Customers can be used to optimize the BRP’s portfolio (e. g. load shifting services, load-generation optimizations services, self-balancing services).

Constraint management services help the grid operators (TSO and DSO) to optimize grid operation (e. g. congestion management services, voltage profile management services, power quality support, grid capacity management, controlled islanding, redundancy support).

Balancing services include all ancillary services specified by the TSO for frequency regulation (Frequency Containment Reserve, Automatic Frequency Restoration Reserve, Manual Frequency Restoration Reserve, Replacement Reserve).
Adequacy services aim to increase security of supply by organizing sufficient long-term peak and non-peak generation capacity.

Remuneration schemes

The Flexibility Requesting Party, such as TSO and DSO, remunerates the Supplier-Aggregator for providing flexibility services (the delivered flexibility in this case is implicit in the portfolio of the BRP of the Supplier-Aggregator; since Supplier and Aggregator coincide, there is no need for a transfer of energy between them and to “correct the perimeter” of the Supplier due to the activation of flexibility instructed by the Aggregator).
Wholesale services are remunerated in volume (energy) while constraint management services, balancing services and adequacy services may be remunerated in capacity and/or volume. Note that wholesale services are not necessarily separately settled.
Finally, the Supplier-Aggregator remunerates for providing flexibility services the Prosumer / Active Customer based on the contractual conditions.

Main advantages of the Integrated Model

- the Aggregator and the Supplier coincide, therefore there is no need for different BRPs;
- the Aggregator does not need to contract with the Supplier;
- reduced complexity, since supply and flexibility provisions can be aligned from the start;
- no need of “Transfer of Energy” mechanism (the impact of flexibility activation on the Supplier’s sourcing and sales position does not need to be compensated by the Aggregator, because the two roles are combined);
- no need of “perimeter correction”, i.e. of an adjustment of the BRP (of Supplier) perimeter by the TSO based on the activated volume by the Aggregator;
- reduced complexity in market coordination mechanisms.

7 EVOLUTION OF ANCILLARY SERVICES

7.1 Introduction

In general, compared to an integrated and interconnected national system of continental Europe, an island system has some peculiar characteristics that are mainly related to the size of the transport network (e.g. poorly meshed transport network, non-existent interconnection system or with limited exchange capacity), to the amount of demand (e.g. peak load, amplitude of the variable demand profile) and to the technology of the production plants (e.g. few production plants and mainly of fossil thermoelectric type).

This means that in the management and control of the system, the Transmission System Operator (TSO) does not have the same degree of flexibility that it would have in a continental system. In fact, although the problems to be solved are similar (e.g. the maintenance of the grid frequency and of the nodal voltage levels within pre-established operational limits, the provision of sufficient power reserves, also in order to carry out a possible restart of the grid in case of shutdown or black-out), the availability of flexible resources is quite different. In particular, the definition of the sufficient amount of power reserves for the control of the network frequency can be critical in case of presence of few and big production plants, especially if these plants are also not very flexible.

This criticality of procuring the reserve can be further amplified when considering the coexistence of increasing amounts of intermittent renewable generation, mainly from small-medium sized solar photovoltaic and wind power plants connected through inverters to the transmission and distribution system. In fact, in addition to the variability of demand, it is also necessary to consider the variability of the injection into the network by intermittent renewable sources, thus increasing the need for balancing resources. On the other hand, the increase of generation capacity from intermittent renewable sources may involve the partial or total replacement of generation capacity by more polluting plants; if these conventional plants are also dedicated to the provision of regulation and reserve services, the substitution effect by renewables may result in a shortage of reserve capacity. Finally, a decrease of "in-line" regulation capacity may expose the system to transients that may be more destabilizing (e.g. ultra-fast frequency transients due to the effect of the reduction of the system's inertial reaction capacity due to the massive penetration of inverter systems, nodal voltage transients with a strong impact on the local grid voltage profile due to the reduced short-circuit power capacity of the system, also in this case due to the limited contribution of inverter systems) and, in any case, with a negative impact on the system's capacity to host high levels of intermittent renewable production (so-called hosting capacity).

This means that in an island system, the development of renewable generation requires even more a careful assessment of the possible consequences on the security and stability of system operation, thus being able to identify the appropriate countermeasures, such as, for example, the identification of new innovative regulation/reserve services or the partial or total extension of the provision of services to all possible suppliers (i.e. without limits of technology and plant size).

7.2 Innovative ancillary services

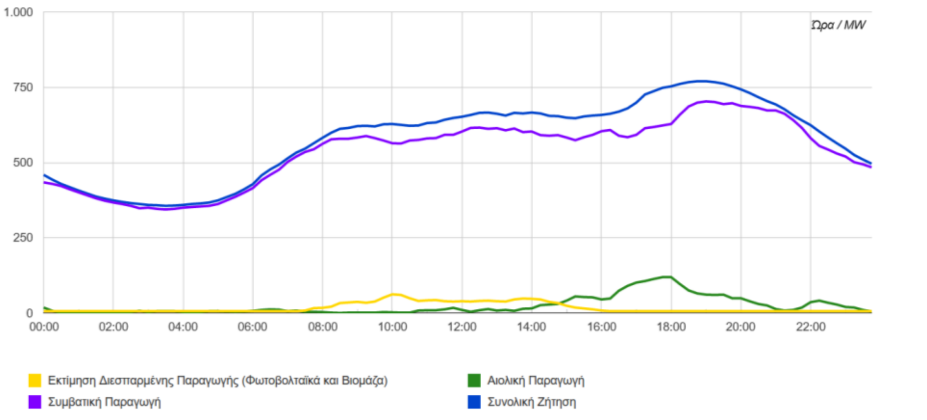
Innovative ancillary services will be fundamental in order to operate the system in a secure way and with resilience characteristics. In the following we will focus on the following ancillary services, already described in detail in Output 2.1:

- ramping margin service,
- services for rate-of-change-of-frequency (ROCOF) and frequency deviation containment,
- Demand Response,
- additional reactive services,
- additional black start capability services.

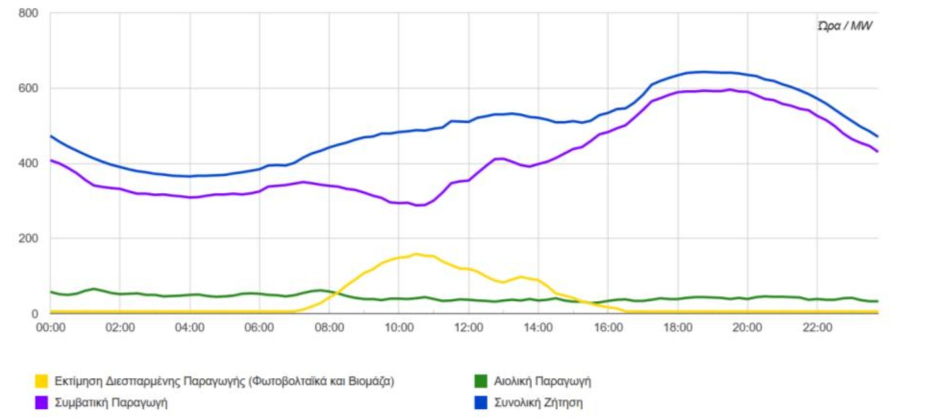
7.2.1 Ramping margin service

With reference to the level of electricity consumption (e.g. peak around 1100 MW in 2019) in Cyprus, to the penetration of renewables foreseen for 2030, especially related to photovoltaic solar, and to the development of gas-fired generation (mainly CCGT plants), the impact of new renewable generation could be relevant first of all taking into account the demand profile during weekdays/holydays and/or during summer/winter seasons. A typical trend on weekdays and holidays of generation and demand is shown in Figure 5; with reference to the profile of net demand (i.e. net of renewable generation, including intermittent generation), both the downward (between 7:00 and 11:00 in the morning) and the upward (between 12:00 and 18:00 in the afternoon-evening) slope of the net demand could be amplified. The afternoon-evening ramp could be particularly problematic as it could imply the need to satisfy a demand characterized by a steep ramp lasting up to 7-8 hours. In this case, the ancillary services needed would have slightly different characteristics with respect to the traditional ones. As a matter of fact, currently the plants are required to have a power reserve which must be able to be activated within a certain time from the disturbance event, while in the future the request could be the duration of maintaining a certain level of supply.

A possible solution is the new Ramping Margin service identified by the TSOs (EIRGRID, SONI) for the Irish system. In practice, it is a matter of identifying, within a given time interval, the amplitude of the upward ramp on the net demand and therefore quantifying the maximum additional power that could be required by the system in the aforementioned interval (Ramping Requirement: see Figure 7) taking into account the uncertainty (blue band in Figure 7) about the variability of both demand and intermittent generation, and the change of power output required from the generation units (Ramping Duty). The Ramping Margin is therefore the upward margin required in addition to the maximum ramp width of the expected demand (Ramping Duty) in the range of interest[13] (see Figure 7). Obviously, the Ramping Margin service can be sized for different lengths of time (e.g. 3 hours, 5 hours, 8 hours).



(a) – 2021, December 14 (Tuesday)



(b) – 2021, December 12 (Sunday)

Figure 5 - Examples of load and generation profiles in Cyprus (source: Cyprus Transmission System Operator – TSOC, https://tsoc.org.cy/) - demand (blue), conventional production (purple), PV & biomass (yellow), wind (green)

[13] EIRGRID, SONI, "DS3: System Services Consultation – New Products and Contractual Arrangements" (8 June 2021). https://www.soni.ltd.uk/media/documents/Archive/System-Services-Consultation-Products.pdf

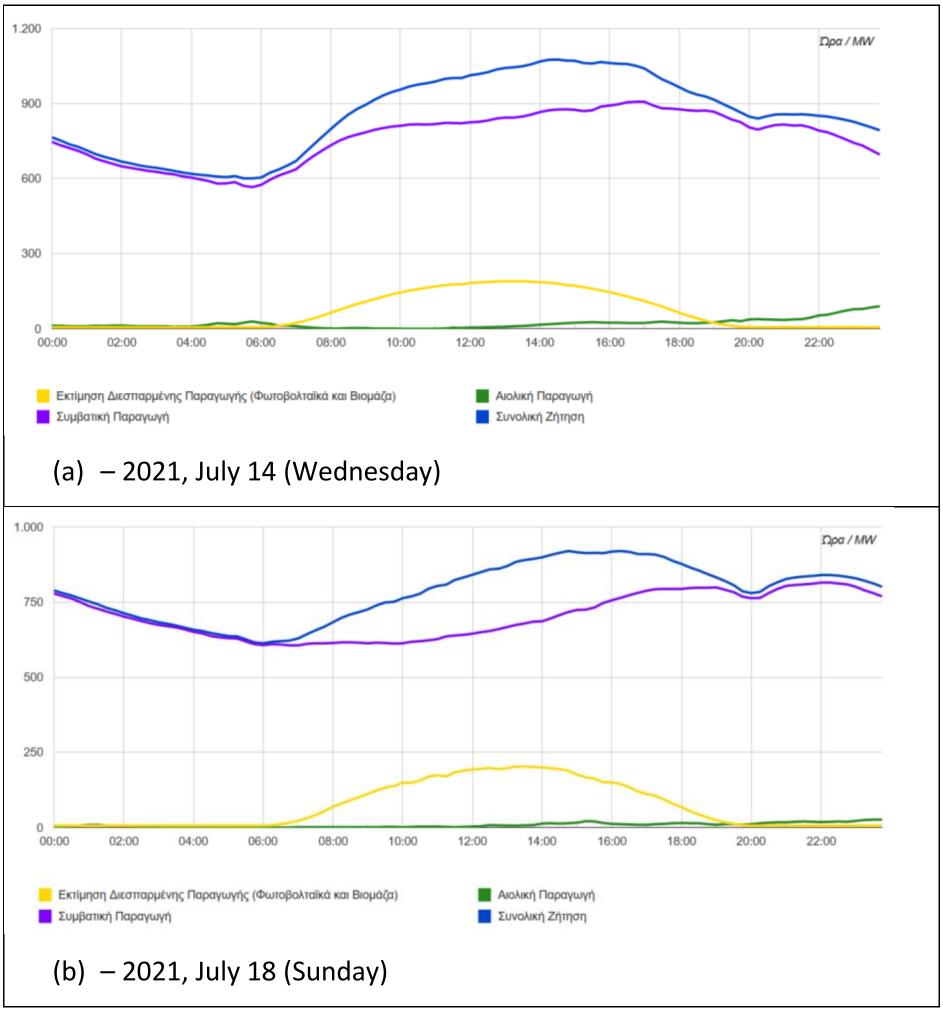


Figure 6 - Examples of load and generation profiles in Cyprus (source: Cyprus Transmission System Operator – TSOC, https://tsoc.org.cy/) - demand (blue), conventional production (purple), PV & biomass (yellow), wind (green)

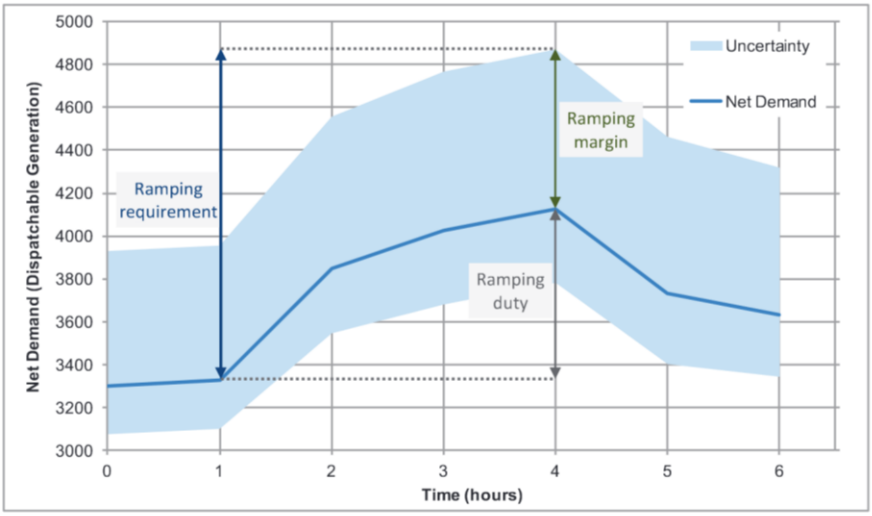


Figure 7 - Example of Ramping Duty, Ramping Margin and Ramping Requirement for a 3h horizon (Source: EIRGRID, SONI)

In the document "DS3 System Service Tariff Rate Review" (28 May 2021) of EIRGRID / SONI reference is made to the document "DS3 System Services Enduring Tariffs" of 2017 in which the procurement mechanisms of the new services has been implemented. The procurement of the three products of Ramping Margin (RM1, RM3, RM8 Services) and of inertia (SIR Service) was started on 1st October 2016 while the procurement of FFR (Fast Frequency Response) started on 1st October 2018 (two other Fast Post Fault Active Power Recovery-FPFAPR and Dynamic Reactive Response DRR services are expected to start soon). All these services are procured through an auction mechanism and the remuneration is at a regulated price[14].

7.2.2 Services for rate-of-change-of-frequency (ROCOF) and frequency deviation containment

The intermittent renewable generation capacity in the 2030 Cyprus scenario is comparable to the peak demand (1100-1200 MW). Under these circumstances, the grid frequency regulation performances assured by conventional thermoelectric plants (mainly gas-fired units) could not be enough, especially in case of failure of the interconnection with the continent. In particular, the containment of the frequency deviations could be problematic due to the reduction of system inertia associated to the displacement of conventional synchronous generating units by non-synchronous renewable units.

A possible solution could be the introduction of “inertia-like” or "fast primary regulation” services in order to contain the frequency deviations by acting since the very first instants after the perturbation event. The final aim of such services is to prevent the activation of distributed underfrequency load shedding and keep system frequency stability. Solutions of this type have been identified by some TSOs, named e.g. Synchronous Inertial Response (EIRGRID / SONI for the Irish system), Fast Frequency Response (EIRGRID / SONI for the Irish system), Enhanced Frequency Response (NG ESO for the Great Britain system), Fast Reserve and wind “inertia” response (TERNA for the Italian system) , as described in detail in Output 2.1.

Non-synchronous generation (i.e. power generators connected to the grid via an inverter interface such as wind generators, solar PV units, storage units) can provide power control in a similar fashion to

[14] https://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Service-Tarrif-Review-Consultation_28-05-2021.pdf
http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Enduring-Tariffs-Consultation-Paper.pdf
https://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Protocol-Recommendations-Paper-with-responses.pdf
https://www.regen.co.uk/wp-content/uploads/Mo-Cloonan-presentation-CER.pptx.pdf

conventional synchronous generators (including the synthetic inertia-like response capability)[15]. In particular, as more inverter-based generators will be connected to the grid and consequently the AC voltage system will become weaker, the power electronic-based generators will need to participate to frequency and voltage control as conventional generators. This will require new control strategies and new inverter design in order to overcome the limited performances ensured by traditional power electronic devices, called "Grid Following Inverters" (i.e. the converter-based device acts like a sinusoidal current source that "follows" the AC voltage seen at its terminals); the next generation inverter-based systems, called "Grid Forming Inverters", will be capable of regulating system voltages and frequency through a local decentralized control; for more details see the Box below). Since the Grid Forming Inverter approach is fundamentally different from the control that is commonly employed today and has currently a low maturity level, so that it will require a significant R&D effort by converter manufacturers[16], we still assume for the Cyprus power system a relevant role of conventional synchronous machines and of conventional power electronic-based generators (Grid Following Inverters).

As far as over frequency events following the loss of loads (or HVDC in exporting conditions) are concerned, the magnitude of the perturbations would be quite smaller than the corresponding underfrequency ones. Moreover, renewables can be directly involved in the provision of downward regulation. This would address any possible criticality.

An important remark to take into account is that, in case of situations of high import from the HVDC connection to the continent associated to relatively high renewable production, the adequacy of primary frequency reserve margins could be questioned. In such conditions, the most constraining contingency for security would likely be the loss of HVDC injection. In case the EuroAsia HVDC is built in a bipolar configuration, security would typically be guaranteed against the loss of one pole, by providing reserve margins in the island. The loss of both poles is a quite unlikely event, which however cannot be excluded. Due to the low probability and high cost, it would not be convenient to keep spinning reserves to face this event, but an adaptive defense scheme could be set up that disconnects specific loads (e.g. industrial loads with special "interruptible" contracts) in real time in case of the event. This scheme could be used also in case of single-pole contingency, in order not to keep too expensive spinning reserve at all times.

[15] In particular, with proper controller design, they can also provide synthetic inertia-like response and ride through various types of balanced and unbalanced under and overvoltage faults and frequency deviations, thus improving the overall reliability of a power system.

[16] ENTSO-E, "High Penetration of Power Electronic Interfaced Power Sources and the potential contribution of grid forming converters", Tech. Report, 2019, ENTSO-E Technical Group on High Penetration of Power Electronic Interfaced Power Sources.

Box 1 – Grid Forming Inverters

In general, all converter-based devices are very flexible so that active and reactive power exchanged with the grid can be controlled independently and quickly. At the Point of Common Coupling (PCC) with the network the terminal voltage can be readily followed and a controlled current can be injected. In fact, the core of the operation of a converter-based device is a Phase-Locked Loop (PLL), which estimates the instantaneous phase angle of the sinusoidal voltage at the converter terminals; subsequently, a controlled active/reactive current is injected into the grid which tracks the sinusoidal terminal voltage. The converter-based device acts like a sinusoidal current source that “follows” the AC voltage seen at its terminals (so-called Grid-Following Inverter). Currently a Grid-Following Inverter is the most common application for wind generators and on-grid photovoltaic systems. The main assumption is that the collective behavior of the power system, and of associated control systems, results in sufficiently stable frequency and voltage at any point on the grid. Currently this assumption is reasonably robust given the comparatively low share of converter-based devices in many power systems. However, as more converter-based devices are connected to the grid (up to the extreme case of 100% converter-based devices), the presence of only Grid-Following Inverters becomes challenging, if not infeasible, since such converters act merely as voltage-following current sources (which assets will perform voltage regulation?). In fact, in presence of large conventional synchronous generators at the transmission system level, both the frequency and terminal voltage can be controlled through the shaft torque and the field current, respectively. In particular, during the perturbation events, the energy stored in rotating masses and the reactive power capability of the generation unit ensure the stability of frequency and voltage. In contrast to a conventional generator, a Grid-Following Inverter-based device is strictly electronic (with limited current capability, i.e. the rated power is typically 2-3 orders of magnitude smaller compared to large conventional synchronous generation units) and does not contain any mechanical components or rotating masses providing inertia, so that it does not exhibit the physical properties of conventional machines (the Grid-Following Inverter-based devices physical response is dictated by how its digital control is programmed). In other words, a system with low inertia and low reactive power capability is vulnerable to larger and undesirable frequency and voltage deviations.

In view of a possible future 100% power electronic-based grid, due to the penetration of renewable sources and the phase out of fossil ones, an alternative converter design is required that must be capable of regulating system voltages and frequency through a local de-centralized control, similarly to conventional machines. These new power electronic-based converters are named Grid-Forming

Inverters. In particular, according to the results of the MIGRATE European research project[17], Grid-Forming Inverters must have the following features:

- controllers must be compatible with existing systems;
- robust operation, involving multiple converters distributed over a large geographical area, without requiring real-time communications for fast control (decentralised control);
- ability to operate without synchronous machines being present;
- active and reactive power controls, while ensuring adequate power quality for energy supply to loads.

With respect to the conventional Grid-Following Inverter, that acts like a sinusoidal current source due to the nature of a "voltage source", a Grid-Forming Inverter actively responds to external system changes and disturbances, such as network faults. In particular, for the active power control loop, a Grid-Forming Inverter behaves in a similar manner to the traditional droop control of synchronous machines; however, it uses the measured active power at the PCC to adjust the frequency of its output voltage. Besides, the voltage at the PCC is maintained by controlling the voltage at the inverter output, taking into account the reactive power output via the voltage/reactive power droop.
Simulation results carried out on the Irish power system (that is larger than the Cyprus one, but has some similarities due to the fact that both countries are islands) can be summarized as follows:

- Grid-Forming Inverters provide voltage source behavior at the grid frequency; in particular, simulations of the Irish power system showed that a system consisting only of Grid-Forming Inverters is robust against bolted 3-phase faults (considering a 250 ms duration), with no or very little oscillations observed during and post-fault, and with small variations in performance depending on fault location;
- Grid-Forming Inverters require new controls;
- in order to identify a lower bound on the Grid-Forming requirements (relative to Grid-Following converters), various disturbances were applied at all network nodes for a range of converter configurations, and the ability of the system to satisfactorily survive such disturbances was observed. It was seen that a minimum of 37.5% of the total online converter capacity (MVA) should be Grid-Forming, recognising the test system characteristics and

[17] MIGRATE – Massive InteGRATion of power Electronic devices, "New options in System Operations", Deliverable 3.4, 31 January 2019, https://www.h2020-migrate.eu/_Resources/Persistent/5d0f8339650bcf53cd24a3006556daa1da66cb42/D3.4%20-%20New%20Options%20in%20System%20Operations.pdf

assuming that the individual converter bus nodes were either Grid-Forming or Grid-Following in nature, but not a combination of both;

- the stability boundary, associated with the minimum Grid-Forming requirement, is ultimately dependent on the PLL gains of the Grid-Following Inverters;
- the ability of a PLL of the Grid-Following Inverters to operate correctly under fault conditions depends on the proximity to the fault location, but it also depend on the duration of the fault.
- IT is plausible that power electronic-based devices will be much smaller in rating, and distributed somewhat unevenly around the network; consequently, individual buses may consist of a mix of Grid-Forming and Grid-Following converters, and different buses may experience different Grid-Forming shares. Under this assumption, it was seen that the Grid-Forming requirement can be reduced from a 37.5% share to approximately 30%, measured as a system-wide average.

7.2.3 Demand Response

In the presence of a shortage of upward reserve, the TSO can arrange for a planned shedding of consumption units. In this case, it will be necessary to have consumption plants willing to carry out the partial or total disconnection of the power taken from the grid. Generally this service is offered as an interruptible service reserved for some particularly energy-intensive plants[18] but the possibility of modulating demand could also be extended to smaller consumption units, also in combination with local generation units (so-called Demand Side Flexibility service - DSF). Examples of such DSF services are the interruptible service defined in Italy, Germany and Spain, the *Short Term Operating Reserve and Demand Turn Up* services that have been defined for the UK system, the *Interruptible Contract Holder*, *Tertiary Reserve services with Dynamic Profile* and *Tertiary Reserve Flexible* defined in the Belgian system or the Demand Response services *Notification d'Échange de Blocs d'Effacement* defined in the French system[19,20].

[18] Such kind of plants have typically a base-load consumption, therefore they can always contribute to reducing the system peak load.

[19] SMARTEN, “Explicit Demand Response in Europe - Mapping the Market 2017” (April 2017) https://www.smarten.eu/wp-content/uploads/2017/04/SEDC-Explicit-Demand-Response-in-Europe-Mapping-the-Markets-2017.pdf

[20] SMARTEN, “The European SmartEn Map - European Balancing Market Edition 2018” (2018)

7.2.4 Additional reactive services

As the renewable generation contribution from non-synchronous generators increases, the voltage regulation capacity may decrease due to the decrease of the reactive power margin provided by conventional plants. In particular, the reduction of the short-circuit power can increase the degradation of the under-fault voltage profile thus leading to the risk of disconnection of further generation capacity. Therefore, in the absence of additional control resources, an alternative can be represented by the introduction of some additional control functions in order to allow the overcoming of a failure event without the risk of triggering further destabilizing phenomena in the system. For example, in addition to the ability to withstand voltage dips (*Fault Ride Through Capability*), non-synchronous generators may be required to carry out an additional injection of sub-fault reactive current and/or the possibility of recovering the pre-failure input level. These services have been identified in the European Network Code for generation plants as *Reactive Power Injection* and *Fast Post-Fault Active Power Recovery* services.

7.2.5 Additional black start capability services

In the presence of few conventional power plants and of a large amount of distributed generation mainly represented by intermittent renewable plants and flexible demand, a new black start capability service could be identified, obtained through the combination of the technical characteristics of the generation and load units with the possible support, in case, of storage units. One example of this is the *Combined Black Start Service* concept introduced by the TSO NG ESO in Great Britain[21].

7.3 New ancillary service providers and aggregated resources

In a scenario of high penetration of renewable generation, storage systems and flexible consumption, an increase of the need for flexibility resources can also be obtained by expanding the number of participants. This implies the possibility of some technologies until now excluded or only partially exploited to be able to actively participate in the control of the system with the possibility of an economic compensation. For example, in the presence of an interconnection system with the continental area via an HVDC connection, part of the reserve and regulation needs can be satisfied by the interconnector itself (e.g. contribution to

https://www.smarten.eu/wp-content/uploads/2018/11/the_smarten_map_2018.pdf

[21] NG ESO, “Product Roadmap - Restoration” (May 2018). https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Restoration.pdf

frequency/voltage regulation and support in re-start or restoration phase). Furthermore, participation in regulation services may also be extended to Distributed Energy Resources such as the generation and load units or the storage systems directly connected to the distribution system; in this case it will also be necessary to introduce mechanisms for aggregating this kind of resources (see also chapter 6). Distributed resources are very composite both in terms of technology and size so, for the purposes of participating in the ancillary service markets, it will be necessary for the service provider (Balancing Service Provider) to be able to build a portfolio of resources with specific characteristics corresponding to the characteristics of the services requested by the TSO[22].

In this case, examples of how these aggregations could be are:

- controlled Virtual Units defined on the basis of Pilot Projects identified by the Italian TSO for participation in the services of Fast Reserve, Secondary Reserve, Tertiary Reserve/Balancing Service and Voltage Control[23] (see Output 2.1 for further details);
- Virtual Power Plants according to the German model of Next Kraftwerke[24] or to the Swiss model[22].

Within each Virtual Unit it is possible to aggregate both consumption units and generation units, including electrochemical storage units.

7.4 Summary of recommendations

To summarize, an island system, such as the Cyprus one, has specific characteristics that are mainly related to the size of the transport network, to the amount of demand as well as to the technology of the production plants. In particular, the definition of the sufficient amount of power reserves for the control of the network frequency can be critical in case of presence of few and big production plants, especially if these plants are also not very flexible.

This means that, in an island system, the development of renewable generation requires even more a careful assessment of the possible consequences and, for this reason, it is important to identify new innovative regulation/reserve services.

[22] Penta SGIII, "Expert Group Demand Side Response" (May 2017).
https://www.benelux.int/files/1215/1749/6862/Penta_EG2_DSR_Paper.pdf

[23] TERNA, "Progetti Pilota ai sensi della delibera ARERA 300/2017/R/EEL" (on-line).
https://www.terna.it/it/sistema-elettrico/progetti-pilota-delibera-arera-300-2017-reel

[24] Next Kraftwerke, "Virtual Power Plant - How to Network Distributed Energy Resources" (on-line).
https://www.next-kraftwerke.com/wp-content/uploads/brochure-nemocs-next-kraftwerke.pdf
https://www.next-kraftwerke.com/vpp/virtual-power-plant

Table 3 provides a summary of different services that could be implemented in Cyprus in order to face these issues.

Table 3 - Summary of new services that could benefit the secure operation of the future Cyprus power system

Service	Description
Ramping margin service	The new Ramping Margin service identified by the TSOs (EIRGRID, SONI) for the Irish system.
Frequency gradient containment services	The introduction of an inertial response service or primary regulation faster than the traditional one in order to be able to compensate for the rapid variation of the frequency gradient in the very first moments of the perturbation event.
Demand Response	An interruptible service reserved for some particularly energy-intensive plants, but the possibility of modulating demand could also be extended to smaller consumption units, also in combination with local generation units (so-called Demand Side Flexibility service - DSF).
Additional reactive services	Introduction of some additional control functions in order to allow the overcoming of a failure event without the risk of triggering further destabilizing phenomena in the system. For example, in addition to the ability to withstand voltage dips (*Fault Ride Through Capability*), non-synchronous generators may be required to carry out an additional injection of sub-fault reactive current and/or the possibility of recovering the pre-failure input level. These services have been identified in the European Network Code for generation plants as *Reactive Power Injection* and *Fast Post-Fault Active Power Recovery* services.
Black start capability services	In the presence of few conventional power plants and of a large amount of distributed generation mainly represented by intermittent renewable plants and flexible demand, a new black start capability service could be identified, obtained through the combination of the technical characteristics of the generation and load units with the possible support, in case, of storage units. One example of this is the Combined Black Start Service concept introduced by the TSO NG ESO in Great Britain.

These services will become more and more relevant for the Cyprus power system, hand in hand with the progressive development of intermittent renewable sources towards the National Energy and Climate Plan 2030 targets, the more ambitious Green Deal targets and the 2050 full decarbonization ones. Within these frameworks, the services listed above will be essential in order to operate the system in a secure way and with resilience characteristics.

In principle, each service may be voluntary or mandatory, remunerated or non-remunerated and, in the former case, remunerated by a market or in an administrative way.

It is generally observed that frequency regulation reserves are typically procured with market procedures. Voltage regulation is a more local service, so it is not always possible to create a competitive and perfectly functioning voltage market; for this reason, in most of the analyzed countries, this service is treated not as a regulated market but, for the actors who are able to provide voltage regulation, as a mandatory service at a regulated price.

The choice whether making the services mandatory or not must be taken by analyzing the Cyprus system as a whole in different relevant scenarios, in order to account for the peculiarities of the transmission and distribution networks (e.g. through power flow studies, etc.), but taking also into account the expected number of resources available to provide each service, that in a small system like the Cyprus one might be limited.

As for the remuneration, in principle if the provision of a service entails costs for the service provider they should be covered, as well as granting a fair profit margin. All this should be left to the market, but if the expected number of service providers is limited, the only solution to avoid market power abuse is to set the remuneration in an administrative way.

Taking into account that Cyprus is still in the first phase of the electricity market operation and that the impact of the development of intermittent renewable sources will become relevant in a 2030 time horizon, in order to implement these services, as well as to involve as service providers aggregates of mixed resources, it is suggested to proceed through a first implementation of pilot projects that can give specific and precious indications for their full future implementation.