# Industry4Redispatch (I4RD)

## Deliverable 3.2

## Regulatory Analysis


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# TABLE OF CONTENTS

## LIST OF FIGURES



## LIST OF TABLES

# GLOSSARY

### ACER
European Union Agency for the Cooperation of Energy Regulators

### CACM
CACM is the abbreviation for the Commission Regulation (EU) 2015/1222 [1] on capacity allocation and congestion management.

### CEP
The Clean Energy Package (CEP) [2] is a comprehensive set of regulations and directives aimed at updating the European energy policy framework in order to facilitate the transition away from fossil fuels towards cleaner energy and to deliver on the EU's Paris Agreement commitments for reducing greenhouse gas emissions. In the context of system operation, the CEP introduces relevant regulatory framework on the internal market for electricity, specifically the Regulation (EU) 2019/943 [3] as well as the Directive (EU) 2019/944 [4].

### CHP (Plant)
Combined heat and power (plant)

### CROSA
*"'CROSA' or 'coordinated regional operational security assessment' means a process of an operational security analysis performed by RSC(s) in accordance with Article 78 of the SO Regulation"* [5]

### CSA
CSA stands for the coordinated security analysis as defined in the "methodology for coordinating operational security analysis" (CSAM) [6].

### E-ControlG
The "Energie-Control-Gesetz" (engl.: Energy-Control regulation) [7] regulates the roles and responsibilities of the Austrian regulatory authority, E-Control.

### Electricity Directive
Directive (EU) 2019/944 of the European Parliament and of the council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU. [4]

### Electricity Regulation
Regulation (EU) 2019/943 of the European Parliament and of the council of 5 June 2019 on the internal market for electricity. [3]

### ElWOG
The "Elektrizitätswitschafts- und -organisationsgesetz" (engl. Electricity Industry and Organization Act) [8] regulates generation, transmission, distribution and supply of electricity as well as the organization of the electricity sector. It regulates the system charges and provides rules on billing, internal organisation, unbundling and transparency of the accounts of electricity companies.

### Framework Guideline on Demand Response

The Framework Guideline on Demand Response is a draft prepared by ACER pursuant to Art. 59.1(e) Electricity Regulation and based on a request from the European Commission. The Framework Guideline aims at setting clear principles for the development of harmonised rules regarding demand response including rules on aggregation energy storage and demand curtailment for balancing, congestion management and voltage control. [9]

### FSP

Flexibility service provider

### IGM/CGM

Individual grid model (IGM) and common grid model (CGM) are exchanged during the international grid security analysis. First the IGM of the individual TSOs are sent to the Regional Coordination Center which merges the IGMs into a common grid model. The latter is then used for international calculations and processes.

### Member state

Member state in the context of European regulations refers to the member states of the European Union.

### N-1 criterion

*"'(N-1) criterion' means the rule according to which the elements remaining in operation within a TSO's control area after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits"* as defined in Art. 3 (2)(14) [10].

### NC DCC

The EU Regulation 2016/1388 [11], also known as NC DCC (Network code on Demand Connection), contains exhaustive and non-exhaustive (to be regulated nationally) requirements for demand facilities and distribution facilities with transmission system connection, distribution systems including closed distribution systems and demand units, used by a demand facility or a closed distribution system to provide load control services to relevant system operators and relevant TSOs [12]. The NC DCC includes requirements for frequency, voltage, short-circuit withstand capability, reactive power, protection, control, demand disconnection and demand reconnection, power quality, information exchange and simulation models.

### NC RfG

Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators, also known as NC RfG [13] describes requirements for new power generation modules for connection to electricity grids.

### NEP-VO

The "Netzengpassentgelt-Verordnung" (engl. Grid congestion remuneration regulation) [14] regulates the calculation of the remuneration of redispatch not based on contracts between the TSO and the plat operator but by direction of the TSO.

### NRA

NRA stands for national regulatory authority; In Austria, E-Control is the NRA.

### Power Availability Schedule (PAS)

Power Availability Schedules are defined in the “SoMa Schedules” (GER: “Fahrpläne”, formally chapter 3) [15] and are a time series format used to describe the availability, maximum production capacity and lead times of an asset.

### Power Production Schedules (PPS)

Power Production Schedules are defined in “SoMa Schedules” [15] and define a time series format which describes the expected future power generation or consumption of an asset.

### RAIF

The Remedial Action Influence Factor is introduced by Art. 2 (aa) ROSC and defined as *“a flow deviation on a XNEC* [cross-border relevant network element with contingency’] *resulting from the application of a remedial action, normalised by the PATL on the associated XNE* [cross-border relevant network element]*;”* [5] PATL is defined as *“the maximum loading in amperes, MW or MVA that can be sustained on a network element for an unlimited duration without risk to the equipment;”* in accordance with Art. 2 (hh) ROSC.

### RAO

Remedial Action Optimisation

### “Regelzonenführer”(GER) / LFC Operator / Control Area Operator

The Control Area Operator is responsible for controlling power flows and load frequency control within a control area and is roughly equivalent to the German term “Regelzonenführer”. The term is often used synonymous to TSO and may be fulfilled by a third party. [8]

### Remedial Action

Any action by a TSO/DSO aimed at relieving congestions in the transmission/distribution grid.

### ROSC

The methodology for Regional Operational Security Coordination (ROSC) defines the rules for regional operational security coordination for the respective capacity calculation regions pursuant to SO GL, considering the general principles and goals set out in the SO GL and the CACM. [5]

### RSC/RCC

Regional Security Coordinators *“are companies owned by their clients, the TSOs. They perform services for the TSOs, such as providing a regional model of the grid or advanced calculations to tell TSOs which remedial actions are the most cost-efficient, without being constrained to national borders. Currently, there are three existing RSCs in continental Europe. Their offices are based respectively in Munich (TSC), Belgrade (SCC) and Brussels (Coreso).”* [16] The responsibilities of the RSC have been adopted by the Regional Coordination Centres (RCC) defined in [3].

### Significant grid user (SGU)

SGUs are defined by the SO GL and with certain differences also by the Austrian SOGL Dataexchange-R.

A brief definition of SGUs is presented in [17] as *"the existing and new power generating facility and demand facility deemed by the TSO as significant because of their impact on the transmission system in terms of the security of supply, including provision of ancillary services."*

Article 2 of the SO GL covers the SGUs that are:

1. *"existing and new power generating modules that are, or would be, classified as type B, C and D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631 (2); [the establishment of the categories is regulated by (EU) 2016/631 and integrated into national law by the RfG, which provides thresholds for those categories and is finally regulated by the "TOR Erzeuger"]*
2. *existing and new transmission-connected demand facilities;*
3. *existing and new transmission-connected closed distribution systems;*
4. *existing and new demand facilities, closed distribution systems and third parties if they provide demand response directly to the TSO in accordance with the criteria in Article 27 of Commission Regulation (EU) 2016/1388 (3);*
5. *providers of redispatching of power generating modules or demand facilities by means of aggregation and providers of active power reserve in accordance with Title 8 of Part IV of this Regulation; and*
6. *existing and new high voltage direct current ('HVDC') systems in accordance with the criteria in Article 3(1) of Commission Regulation (EU) 2016/1447 (1)."* [10]

Art. 3 SOGL Dataexchange-R defines significant grid users as:

- *"Significant generation facilities, that are SGUs according to Art. 2 Abs. 1 lit. a SO GL (i.e. electricity generators of RfG Type B, C and D)*
- *Significant demand facilities with a nominal voltage at connection point of ≥ 110 kV, or that provide demand response services directly to the TSO in accordance with Art. 27 DCC and have an installed capacity of ≥ 25 MW"*

### SNE-VO/SNE-V

The „Systemnutzungsentgelte-Verordnung" (engl. System Charge Regulation) [18] defines the system charges for all regions and grid levels in Austria.

### SOGL Dataexchange Regulation (GER.: SOGL Datenaustausch-V)

The SOGL Dataexchange Regulation [19] is a regulation decreed by E-Control, implementing the requirements of Article 40 et seq. of the SO GL [10] in national law. In addition to the requirements of Articles 40 et seq. of the SO GL, the SOGL Dataexchange-Regulation is a national regulation defining additional specifics for data exchange in Austria.

### Sonstige Marktregeln Strom (SoMa)

The Austrian regulatory authority has published the "Sonstige Marktregeln Strom" (SoMa) [20] in accordance with Article 22 paragraph 1 E-ControlG [9] to establish basic processes and standards for the electricity market and are called into effect via the general grid connection conditions of APG and the DSOs.

### System Operation Guideline (SO GL)

SO GL is the abbreviation for the Commission Regulation (EU) 2017/1485 [10] establishing a guideline on electricity transmission system operation.

### “TOR”

TOR stands for „Technische und Organisatorische Regeln für Betreiber und Benutzer von Netzen” (engl.: technical and organizational rules for grid operators and users) [21] and are created as well as published by E-Control in consultation with market participants in accordance with Article 22 paragraph 2 E-ControlG.

### “TOR Begriffe” (engl. TOR definitions)

The „TOR Begriffe“ (engl. TOR definitions) encompasses all definitions relevant to the TOR. [22]

### „TOR Netze und Lasten” (engl. TOR grids and demand)

The technical and organizational rules for grids and demand [23] (GER: “TOR Netze und Lasten”), published by E-Control, specify the requirements for grids and loads with transmission system connection.

### Transmission System Operator

The transmission system operator is the legal person responsible for operating and maintaining the power transmission system.

### XRA/(X)RA/RA

RA is the abbreviation for Remedial Action. XRAs are all remedial Actions that are cross border relevant. (X)RA includes remedial actions with and without cross border relevance. [5]

## 1. Preamble

This regulatory analysis was conducted within the project Industry4Redispatch. It is intended to provide an overview of the current regulatory framework, as well as the resulting implications for the project partners. Discussions and suggestions on regulatory adaptations shall not be viewed as proposals for concrete adaptations, but rather as a starting point for discussions with E-Control. When referring to legal provisions currently in place, nothing in this report shall be interpreted as constituting a binding interpretation of the authors' employers. Furthermore, any statements made in this report on how to improve upon the regulatory framework regarding redispatch may neither be interpreted as representing the official nor legally binding position of the authors' employers. Notwithstanding this disclaimer, this report has been created with utmost care. Hence, neither APG, nor the contributing DSOs, nor the industry partners assume any liability whatsoever regarding this document.

## 2. Introduction

This deliverable has been devised within the Project Industry4Redispatch. Industry4Redispatch is a flagship project aimed at an enabling redispatch provision by industrial facilities at distribution grid level. Within the project, all necessary technical, regulatory, economic and organisational prerequisites for the implementation of redispatch requirements that enable redispatch provision by industrial sites, including virtual powerplants, are investigated. Furthermore, solutions for the interaction between transmission system operators (TSO) and distribution system operators (DSO) are developed.

The deliverable at hand summarises the findings of the projects Task 3.4 (regulatory analysis), which is part of the projects work package 3 (Incentives and Requirements). As part of this task the legal framework governing the use of redispatch as a means of congestion management was analysed and compared to the technical requirements from the projects Task 3.2 (published in the Deliverable 3.3.).

The Analysis of the regulatory framework is documented in sections 3 through 7: Section 3 covers the legal definition of redispatch. Section 4 lays out the obligation of all parties involved. This includes the responsibilities of transmission and distribution system operators as well as those of the providers of redispatch. Section 5 covers the regulatory framework considering data exchanges while section 6 focuses on the requirements applicable to grid users connected to the distribution grid. Section 7 lays out the obligations considering the financial compensation of redispatch.

In section 8 a cross check between legal rights and obligations and technical requirements defined in D 3.3 is performed and possible obstacles to the use of industrial assets for redispatch provision are identified. This comparison has shown the legal definitions of DSO redispatch, the rules regarding the delivery of schedules for loads and the reimbursement of redispatch as the main regulatory topics which must be addressed to enable the provision of redispatch by industrial flexibilities.

After identifying these issues an overview of the redispatch implementation in different European countries is given in chapter 9, to show how different countries implement the international regulations. Section 10 takes a closer look at the barriers identified in the previous sections and lists possible solutions as well as possible pitfalls. Finally, this deliverable summarises the regulatory gaps between the national and international regulatory framework and redispatch requirements and discusses options to adapt the national law in order to facilitate the implementation of the redispatch requirements identified in this project and thus enable participation of industrial facilities in the redispatch process.

## 3. Definition of redispatch

In recent years redispatch has become an important tool for TSOs across Europe to solve congestions and multiple regulations were passed in order to build a legal framework for system operators and providers of redispatch alike. Under Austrian Law, the legal acts governing redispatch are the national **ElWOG** and the respective **NEP-VO.** On European level, redispatch is governed by the EU Regulations and Directives of the third and fourth Package, Regulation (EU) 2017/1485 (hereafter "**SO GL**"), Regulation (EU) 2019/943 (hereafter "**the Electricity Regulation**"), Directive (EU) 2019/944 (hereafter "**the Electricity Directive**") and Regulation (EU) 2015/1222 (Guideline on Capacity Allocation and Congestion Management - hereafter "**CACM"**). The CACM also requires the development of a common methodology for redispatching, countertrading and cost sharing, which is also binding for TSOs and which has been realized by the TSOs in the form of the **ROSC Methodology** for the CCR Core and the ROSC Methodology form CCR Italy North. Furthermore, a Framework Guideline on Demand Response is currently in the consultation phase [9]), which may serve as the basis for the adoption of a network code on demand response, which might introduce further requirements regarding the participation of demand facilities and aggregators as well as the configuration of redispatch requirements and processes. A definition of redispatch may be derived from these legal acts.

This section provides an overview of the definitions for redispatch in those regulatory texts. Within the ElWOG, redispatch is not explicitly defined. However, the ElWOG contains a general definition of congestion management in Art. 7 (13a). The term 'congestion management' is defined in Art. 7 (13a) ElWOG as *"the totality of short-, medium- and long-term measures that can be taken in accordance with the technical system requirements in order to avoid or eliminate congestions in the transmission system, taking into account network security and security of supply;[1]".* One of these measures (also known as remedial actions) is redispatch, which is defined in Regulation 2019/943 (Electricity Regulation), Article 2(26) as *"a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security;".*

As there is more than one way to alter the generation or load pattern of power plants or demand facilities, redispatch may be further differentiated. According to Art. 2(1) of the Methodology for coordinating operational security analysis [6] (hereafter "CSAm"), redispatch measures can be subdivided into preventive redispatch (measures to resolve transmission constraints are taken *ex ante*) and curative redispatch (which is planned beforehand but only activated in case of a contingency). The former is activated during the different coordination phases ranging from timeframes even before the day ahead market coupling up to activations on short notice, close to real-time, regardless of whether the contingency case occurs. The latter is used to solve system security issues only after a contingency case arises and is therefore planned beforehand but only activated close to real time should a contingency case arise. The use of curative remedial actions is limited by a number of factors such as the lead times of technical units and the need for close coordination with other affected TSOs in order to avoid problems in other parts of the grid if measures are suddenly activated.

The aforementioned legal documents not only define the act of redispatching but aim to harmonize the way redispatching is organized and implemented across the Member States of the European Union. This results in provisions stating who shall participate in redispatch, how remedial actions and units for redispatching are selected and how the participants are reimbursed. Regarding the possible participation of technical units in redispatch a wide participation is envisioned as for example required by Art. 17 of the Electricity Directive(EU) 2019/944:

[1] translated by the author

*"Member States shall allow and foster participation of demand response through aggregation. Member States shall allow final customers, including those offering demand response through aggregation[2], to participate alongside producers in a non-discriminatory manner in all electricity markets."* This means that the implementation of a model that enables the participation of aggregators is obligatory.

Regarding the selection of remedial actions and units for redispatching Art. 13 (1) of Electricity Regulation (EU) (2019/943) further states that *"redispatching of generation and redispatching of demand response shall be based on objective, transparent and non-discriminatory criteria. It shall be open to all generation technologies, all energy storage and all demand response, including those located in other Member States unless technically not feasible."*

Regarding the reimbursement of redispatching both cost-based and market-based models are currently in use in Europe and while both are supported by the Electricity Regulation (EU) 2019/943 a non-market-based approach may only be used under certain provisions. The basis for the financial compensation of redispatch in Austria will be further discussed in Section 7. Evidently, redispatching should not be used without a proper cause and should not unduly inhibit the transition towards renewable energy sources. According to Art. 13(5) Regulation (EU) 2019/943 (Electricity Regulation), system operators must guarantee the capability of their networks to transmit electricity produced from renewable energy sources or high-efficiency cogeneration with minimal redispatching. Furthermore, both TSOs and distribution system operators (DSOs) shall *"take appropriate grid-related and market-related operational measures in order to minimize the downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration."* Especially, if non-market-based downward redispatching is used, it is highlighted once again in Art. 13(6) Regulation (EU) 2019/943 (Electricity Regulation), that renewable energy sources shall only be subject to downward redispatching if there are no other possibilities or if the network security is at risk. In case there is no other option, the downward regulation must be duly and transparently justified.

[2] Pursuant to the EU Regulation 2019/944 (Electricity Directive), "'aggregation' means a function performed by a natural or legal person who combines multiple consumer loads or generated electricity for sale, purchase or auction in any electricity market".

# 4. Roles and Responsibilities in the context of Redispatch

The TSOs', DSOs' and technical units' roles and responsibilities in the context of redispatch are defined on European level by the System Operation Guideline (SO GL), the Guideline on Capacity Allocation and Congestion Management (CACM), the Regulation (EU) 2019/943 on the internal market for electricity (Electricity Regulation) and the Directive (EU) 2019/944 on common rules for the internal market for electricity (Electricity Directive). On national level, roles and responsibilities are defined in the ElWOG as well as the provincial electricity laws, which build upon the requirements setforth in the ElWOG. Furthermore, Art. 76 SO GL requires TSOs to jointly develop a proposal for common provisions for regional operational security coordination. This so-called common Methodology for Regional Operational Security Coordination (hereafter "ROSC Methodology") defines the international coordination process of the TSOs of the Core Region, including Austria, for a coordinated redispatch optimisation and activation, which defines additional requirements.

## 4.1. TSOs roles and responsibilities regarding redispatch

In Austria, rules and regulations for redispatch arise for the TSO as the owner/operator of the transmission system or from the role of Control Area Operator (GER: Regelzonenführer).

The foremost responsibility of a TSO is **secure system operation**. The SO GL defines in Art. 18 SO GL operational states of power systems and which criteria must be met to be within a certain state. These system states are mirrored and specified in Austria within the "TOR definitions". According to Art. 20 (1) SO GL, TSOs shall endeavour to ensure that their transmission system remains in normal state. They are thus responsible for managing operational security violations and prepare and activate remedial actions to achieve this objective. In accordance with Art. 21 (2)(a) SO GL, they shall activate the most effective and economically efficient remedial actions. The activation of remedial actions shall be carried out as close to real time as possible taking into account the expected time of activation and the urgency of the situation they intend to resolve. A similar requirement is also described in Art. 23 (2)(5) ElWOG, which defines the obligation of a Control Area Operator to detect congestions and taking any measures related to relieving and overcoming congestion in the transmission grid. These definitions within the Austrian ElWOG must be implemented in federal ElWOGs of the states of Austria. Furthermore, Art. 23 (2)(5) ElWOG stipulates that the Control Area Operator, where necessary, concludes contracts, in agreement with the affected DSO, with producers and consumers of electricity under which the latter are obliged to provide redispatch and are reimbursed for their economic drawbacks and expenses linked to the provision of such redispatch services. Should no such contract exist, a fallback provision grants the Control Area Operator the right to order producers of electricity to adapt their feed-in for redispatching purposes, as set out in Art. 23 (9) ElWOG. For the provision of redispatch on the basis of the order of the Control Area Operator without a contract, a fair remuneration must be determined by the regulatory authority, based on economic disadvantages and costs, pursuant to NEP-VO.

In addition to the obligation to solve congestions, the Control Area Operator must ensure that sufficient capacity for congestion management is available. The Control Area Operator is obliged to carry out a system analysis in accordance with Art. 23a (2) ElWOG to determine the necessary amount of network reserve and to procure the network reserve pursuant to Art. 23b ElWOG. If the volume procured pursuant to Art. 23b ElWOG is deemed insufficient, the decommissioning of producers can be prohibited by the regulatory authority in accordance with Art. 23c (1) ElWOG.

TSO cooperation with respect to congestion management and coordination of remedial actions on the European level is strictly regulated. The general requirements of secure system operation are complemented by more detailed rules covering the specifics of grid operation and how **remedial actions must be coordinated and shared** between different TSOs. Art. 75 SO GL provides principles and requirements for the joint development of a methodology for the coordination of the operational security analysis by all TSOs. This has been executed via the methodology for coordinating operational security analysis (CSAM). Furthermore, Art. 76 SO GL requires TSOs of each capacity calculation region to jointly develop a methodology for the regional, operational security coordination considering the CSAM and the methodologies developed in accordance with Art. 35 and 74 CACM.

The ROSC Methodologies define the rules for regional operational security coordination for the capacity calculation regions pursuant to SO GL, considering the general principles and goals set out in the SO GL and the CACM. It introduces a coordination process with explicit rules for the preparation of cross border relevant remedial actions in a coordinated way and assigns clear responsibilities to the Core TSOs and Core Regional Security Coordinators (RSCs). The standard coordination process is called Coordinated Regional Operational Security Analysis (CROSA). The principles for such CROSAs are defined in Art. 20 of the ROSC Methodology: The Remedial Action Optimization (RAO) objective shall aim at relieving operational security violations in accordance with Art. 22 and 23 of the ROSC Methodology, aim to minimise total costs and revenues of XRAs and aim to minimise the amount and volume of XRAs. Pursuant to Art.24 (3) of the ROSC Methodology, the RAO shall take into account the impact of XRAs on operational security violations with Remedial Action Influence Factor (RAIF), which determines the impact of each remedial action on the power flow or current on cross border relevant network elements and scanned elements. This means that apart from amount/volume and costs of XRA(s), the geographical location and its possible impact on the grid shall be determined and shared to consider the impact on the grid and avoid that the activation of XRA(s) causes operational security violations on other grid elements.

To facilitate a coordinated security analysis, each TSO must deliver relevant input data listed in Art. 13 ROSC Methodology, including all remedial actions that are identified as cross-border relevant and need to be applied in a coordinated way, abbreviated as XRA(s), as well as the corresponding constraints on the activation of XRAs. According to Art. 15 (1) ROSC Methodology *"each Core TSO shall make available all XRAs as identified in Article 9(2) [of the ROSC Methodology] to the Core RSC(s) for each day-ahead and intraday CROSAs […] unless an XRA is not available"*. This obliges the TSO to consider all XRAs during the coordinated remedial action optimisation and thus share redispatch potential for this purpose in the coordinated process.

For national processes to be in line with the ROSC processes, the timing has to be considered. The IGMs are merged to the Common Grid Model ("CGM") at approx. 18:00 for the day-ahead process. This requires that IGMs are already created before 18:00 and also restricts the ability of TSOs to start redispatch calculations. This is due to the fact that redispatch calculations cannot be performed without the Common Grid Models. To enable a timely start of calculations after the merge, all redispatch potentials (bids) including their restrictions must be delivered around the same time. Therefore, redispatch bids should be placed before 18:00 to account for processing of the data.

## 4.2. DSOs' roles and responsibilities regarding redispatch

The DSOs roles and responsibilities are specified in the national ElWOG and individually for each DSO in Austria by the federal ElWOGs for each state. Further additions to the DSOs' responsibilities were recently made by the Directive (EU) 2019/944 (Electricity Directive) which still need to be incorporated into national law.

According to Art. 45 ElWOG, the responsibilities of a distribution system operator shall include:

1. *further development of their distribution networks with foresight and in line with national and European climate and energy targets;*
2. *provision of required data to carry out the calculation and allocation of balance energy […];*
3. *granting of access to its network under approved general terms and conditions;*
   […]
7. *to assess load flows and to monitor maintaining of the system's technical safety*
   […]
10. *measuring the purchases, services, load profiles of the network users, to check their plausibility and to pass on data to the required extent to the balancing group coordinators, concerned network operators and balancing group managers;*
    […]
12. *identification of congestions in the network and taking actions to avoid them;*
    […]
24. *examination of options for integrating interruptible or switchable loads for grid operation in their grid area and, if required, to report them to the Federal Minister for Climate Protection, Environment, Energy, Mobility Innovation and Technology and to the regulatory authority […]*

The result of these national requirements is that all federal ElWOGs contain a paragraph requiring secure (and in some implementations reliable) system operation. Most national ElWOGs also contain a paragraph requiring the DSO to detect congestions and take measures to avoid congestions but only three of them contain a regulation similar to the TSOs rights, which would allow the DSO to enter into contracts with owner of generating assets. Table 1 list the federal ElWOGs, the paragraph governing DSO obligations and whether congestions shall be avoided or may be addressed by contracts with owners of generators.

| State | Law | DSO Obligation regarding secure system operation | Avoiding Congestions | Contracts with assets for generation |
|---|---|---|---|---|
| **Vienna** | Wiener Elektrizitätswirtschaftsgesetz 2005 [24] | Art. 38 (1) 1-3 | Art. 38 (1) 16 | Art. 38 (1) 16 |
| **Lower Austria** | Elektrizitätswesengesetz 2005 [25] | Art. 38 (1) 1-3 | Art. 38 (1) 16 | Art. 38 (1) 16 |
| **Upper Austria** | Oö. Elektrizitätswirtschafts- und -organisationsgesetz 2006 [26] | Art. 40 (6) | Art. 40 (11) | Art. 40 (11) |
| **Styria** | Steiermärkisches Elektrizitätswirtschafts- und -organisationsgesetz 2005 [27] | Art. 29 (1) 6,7 | Art. 29 (12) | - |
| **Salzburg** | Salzburger Landeselektrizitätsgesetz 1999 [28] | Art. 18 (7) | Art. 18 (12) | - |
| **Burgenland** | Burgenländisches Elektrizitätswesengesetz 2006 - Bgld. ElWG 2006 [29] | Art. 32 (1) 1, 11 | Art. 32 (16) | - |
| **Carinthia** | Kärntner Elektrizitätswirtschafts- und -organisationsgesetz 2011 [30] | Art. 43 (f) (g) | Art. 43 (l) | - |
| **Tyrol** | Elektrizitätsgesetz 2012 - TEG 2012 [31] | Art. 50 (1) a-c | Art. 50 (1) (m) | - |
| **Vorarlberg** | Elektrizitätswirtschaftsgesetz [32] | Art. 34 (a) | Art. 34 (k) | - |

***Table 1 Overview of DSO obligations in federal ElWOGs***

Whereas all federal implementations bind the DSO to secure system operation the "Elektrizitätswirtschafts- und -organisationsgesetz (2006)" (engl. Electricity Industry and Organization Law) in Upper-Austria is special as it explicitly specifies in Article 47(1) that *„network operators have to operate and maintain a secure, reliable and efficient* *transmission or distribution network with due regard for environmental protection and, in this context, ensure the provision of ancillary services, aiming at the (n-1) criterion in the construction, operation and maintenance of the extra-high, high and medium voltage networks[3]"*. Thereby, explicitly listing the n-1 criterion as a goal for secure system operation. However, it is still worded in such a way that the (n-1) criterion should be the target for network level 5 and above (which does not mean uninterrupted supply).

The new rules foreseen by the Clean Energy Package envision a **wider use of flexible resources** and market-based procurement of redispatch as the base case. To achieve this, the Electricity Directive explicitly addresses how to create a level playing field for suppliers of flexibility. Art. 31 of Directive 2019/944 (Electricity Directive) lays out the tasks of DSOs. It stipulates that *"[t]he distribution system operator shall be responsible for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity, for operating, maintaining, and developing under economic conditions a secure, reliable and efficient electricity distribution system in its area with due regard for the environment and energy efficiency."* Art. 32 (1) Directive 2019/944 (Electricity Directive) further addresses the topic of incentives for the use of flexibilities in distribution networks. Art. 32(1) states that *"[m]ember states shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, **including congestion management** in their areas […]"*.

Moreover, DSOs *"shall procure such [flexibility] services in accordance with transparent, non-discriminatory and market-based procedures […]"* unless decided otherwise by the regulatory authorities. Art. 32(2) Directive 2019/944 (Electricity Directive) specifies that DSOs shall introduce standardized market products for flexibility services at least on the national level to ensure *"the effective and non-discriminatory participation of all market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation"*. For this, DSOs shall exchange all necessary information and coordinate with TSOs *"to ensure the secure and efficient operation of the system and to facilitate market development".* In particular, the regulatory framework shall ensure that DSOs procure flexibility services from distributed generation, load control or energy storage providers and promote the deployment of energy efficiency measures where such services reduce the need for retrofitting or capacity replacement in a cost-effective manner and support the efficient and secure operation of the distribution systems. Procurement of such flexibility services shall be conducted in accordance with transparent, non-discriminatory and market-based procedures, unless the regulatory authorities have determined that the procurement of such services is not economically efficient or that such procurement would lead to serious market distortions or increased congestion.

Active feed-in management and curtailment practiced by the DSO is not explicitly mentioned in any of the considered regulatory documents. Nevertheless, it is important to consider that all grid connection agreements apply to a state of normal grid operation. According to the federal ElWOGs it is the DSOs' responsibility is to maintain and where feasible restore normal grid operations (e.g. §38 (1) Wiener Elektrizitätswirtschaftsgesetz 2005 [24] and respectively VII. (7) and XXV. (5) c ANB der Wiener Netze [33]). To achieve this, they are allowed to take different measures, including disconnection of grid areas or elements. Moreover, it is possible to regulate different terms and conditions in the grid connection agreement, such as limiting the power at which a facility may feed electricity into the grid.

The DSOs role to enable the activation of redispatch resources in its grid area by coordinating and exchanging all relevant data with the TSO is regulated on European as well as national level. However, the DSOs role as a redispatch requester is only mentioned in the Directive 2019/944 (Electricity Directive) which has not been fully implemented

[3] Translated by the author

into national law as of yet. The option of the DSO to enter into contracts on redispatch with owners of generating assets is foreseen explicitly in only three of the nine federal laws as shown in Table 1.

## 4.3. Technical units' roles and responsibilities regarding redispatch

The technical units' roles and responsibilities regarding redispatch are set out on European level by Regulation (EU) 2019/943 (Electricity Regulation) and Regulation 2015/1222 (CACM) and on national level in the ElWOG. The responsibilities of units performing redispatch encompass adhering to the connection agreements and technical rules (TOR), 5.

Currently, Art. 66 (1)(6) and (1)(7) ElWOG oblige producers of electrical energy to offer redispatch. Producers have to offer redispatch based on contracts concluded between the Control Area Operator and the plant operator and are reimbursed for economic drawbacks and costs. In case no such contract exists, producers of electrical energy are obliged to provide redispatch as requested by the Control Area Operator in accordance with Art. 66 (1)(7) and costs will be determined ex post. At the moment, the ElWOG does not contain a similar provision for consumers of electrical energy. By allowing the TSO to enter into contracts with consumers of electrical energy, offering redispatch is also possible for demand facilities, but there is no legal requirement for consumers to perform redispatch services on the request of the Control Area Operator. Pursuant to Art. 13 of Regulation (EU) 2019/943 (Electricity Regulation) not only generation, but also energy storage and demand response shall be enabled to provide redispatch. However, there is no obligation for these market participants to do so. Such a regulation for consumers for their obligatory participation in redispatch might secure more redispatch potential in the future. However, it would also entail a lot of additional questions as the technical and economic feasibility and availability of redispatch potential of these assets cannot be determined as easily as for generators of electricity. The definition of such a requirement and the evaluation of the effects associated with an obligation to participate are outside the scope of this project. Any of the available redispatch resources may not only be used by the TSO for national purposes, but also for international use as described in Art. 35 (3) of Regulation 2015/1222 (CACM).

Besides the requirement for producers of electricity to participate in redispatch, any resource providing redispatch to the TSO must share the associated costs before the redispatch is activated by the TSO. Art. 35 (5) of CACM determines the timing when redispatch costs must be communicated, *"The relevant generation units and loads shall give TSOs the prices of redispatching and countertrading* ***before*** *redispatching and countertrading resources are committed. […] Generation units and loads shall ex-ante provide all information necessary for calculating the redispatching and countertrading cost to the relevant TSOs."* This means that the costs must be communicated before remedial actions are optimised, which is relevant for the timing of bid submission. To enable the TSO to consider the redispatch (bids) in the international CROSA pursuant to the ROSC Methodology, price information for redispatch shall therefore be made available to the TSO before 18:00 for the day-ahead process.

The costs of redispatch bids that were activated during the international CROSA are subject to cost sharing between TSOs pursuant to Art. 34 ROSC Methodology. Subject to the cost sharing are the costs used during the RAO process as well as any deviations that result from the differences between the prices and costs per volume, provided for the execution of the RAO, and the final incurred costs per volume or settled costs per volume. The latter can only be considered within the cost sharing process until 90 days after the end of a given quarter. Therefore, in case of a cost-based or a cost+ model any deviations from the initially submitted bids must be announced as soon as possible and before the given deadline by the flexibility service provider (FSP). Furthermore, deviations from the initial prices of the bids are monitored by the Core TSOs and measures are to be taken to minimise deviations. Thus, FSPs should seek to keep such deviations to a minimum. This does not mean that any deviations of costs are automatically acknowledged.

**Participating in grid reserve:**

Grid reserve (GER: "Netzreserve") is a mechanism implemented in Austria to ensure sufficient redispatch capacity at all times. This mechanism allows APG to contract operators of electricity generation and demand facilities to ensure their continued availability for redispatch. This requires that the control area operator has knowledge about intentions to mothball or decommission generation units. For this purpose, producers of electric energy with an installed generation capacity above 20 MW are required to notify the Control Area Operator and the National Regulatory Authority about any intentions to decommission or mothball a power plant. Producers and consumers may participate in the tender procedure for the grid reserve pursuant to Art. 23b ElWOG, if deemed technically suitable. This requires that units can guarantee their availability throughout the year and that the change in power associated with a redispatch can be sustained for a minimum duration of 6 hours. The full conditions for participation can be found on the APG Website [34]. Power plants above 20 MW may only participate if they have notified their decommissioning or mothballing. Once power plants are awarded with a contract for the provision of grid reserve, they may not participate in the electricity market for the duration of the contract. If the required volume of grid reserve cannot be procured via the tender procedure pursuant to Art. 23b ElWOG, E-Control, the national regulatory authority may forbid the decommissioning of powerplants in order to maintain sufficient redispatch resources to ensure operational security.

## 5. Data exchange between TSO, DSOs and Redispatch Resources

As described in Deliverable 3.3, redispatch and grid security analysis requires that the concerned TSO or DSO has information on the geographic and topological location of all relevant assets, their forecasted or intended schedules and their potential to perform redispatch. For monitoring purposes measurement and metering data are required. All of this information must be exchanged between the involved parties. The main regulatory text defining the relevant data exchanges between assets, their connecting DSO and the TSO is the Regulation (EU) 2017/1485 (SO GL) in Art. 40 to 53. Any confidential information received, exchanged or transmitted pursuant to the SO GL shall be subject to the conditions of professional secrecy as laid out in Art. 12 SO GL and applies to TSOs, DSOs, SGUs and other persons that are subject of the SO GL.

On national level, the requirements of the SO GL are operationalised by the chapters 2, 3 (Schedules) and 10 "Sonstige Marktregeln Strom" (SoMa) and the SOGL Dataexchange-R[4]. The Austrian regulatory authority publishes the SoMa in accordance with Art. 22 (1) E-ControlG to establish basic processes and standards for the electricity market. SoMa chapter 10 extends the regulations on data exchanges between network operators and the Control Area Operator: Network operators have to deliver energy data with a granularity of ¼ hour for all power plants that deliver nodal schedules as well as aggregated data for balancing providers. Furthermore, "SoMa Schedules" (formally chapter 3), states that, network operators and the Control Area Operator need the actual power plant unit specific measurements as ¼ hour values to evaluate the quality of schedules. Those have to be delivered by producers in a timely manner, at least on the following day.

The SO GL is structured by structural data/master data, scheduled data and real-time data and contains different rules for generation facilities and demand facilities. Therefore, this text follows a similar structure and summarizes the requirements for generation and demand facilities for each of these topics. To begin with, the parties required to transmit data to the TSO/DSO must be defined. To achieve this the SO GL introduces the concept of significant grid users (SGUs) and then introduces a subset of SGUs for which the SO GL applies. These SGUs are defined in Art. 2 of the SO GL as:

- (a) *"existing and new power generating modules that are, or would be, classified as type B, C and D in accordance with the criteria set out in Article 5 of Commission Regulation (EU) 2016/631*[5]*;*
- (b) *existing and new transmission-connected demand facilities;*
- (c) *existing and new transmission-connected closed distribution systems;*
- (d) *existing and new demand facilities, closed distribution systems and third parties if they provide demand response directly to the TSO in accordance with the criteria in Article 27 of Commission Regulation (EU) 2016/1388 (3);*
- (e) *providers of redispatching of power generating modules or demand facilities by means of aggregation and providers of active power reserve in accordance with Title 8 of Part IV of this Regulation; and*
- (f) *existing and new high voltage direct current ('HVDC') systems in accordance with the criteria in Article 3(1) of Commission Regulation (EU) 2016/1447 (1)."*

Art. 2 clearly specifies that the SO GL applies to certain grid users not only based on their size or technical characteristics but also simply for their role as providers of redispatch. Before describing the details of data exchange, Art. 33 (3) SO GL describes the contingency analysis on TSO side and states that *"Each transmission-connected DSO and SGU which is a power generating facility shall deliver all information relevant for contingency analysis as requested by the TSO, including forecast and real-time data, with possible data aggregation in accordance with Article 50(2)."* Thereby, these significant grid users are obliged to provide the data required by the TSO, even if they do not participate in redispatch. The Austrian SOGL Dataexchange-R aims to operationalize the requirements of the SO GL. The SOGL Dataexchange-R also creates new definitions for significant generation facilities and significant

[4] GER: SOGL Datenaustausch-V

[5] The establishment of the categories is regulated by Regulation (EU) 2016/631 (RfG) which provides thresholds for those categories and is finally regulated nationally by the "TOR Erzeuger".

demand facilities. Significant generation facilities are defined exactly as in Art. 2 (1) lit. a) SO GL. The definition of significant demand facilities is further limited in the SOGL Dataexchange-R to assets above 110 kV and above 25 MW installed capacity.

The SO GL does not only regulate the data exchange between SGUs and TSOs or DSOs but also between TSOs and DSOs. According to Art. 43 SO GL, TSOs shall determine the observability area of the transmission-connected distribution systems which is needed for the TSO to determine the system state accurately and efficiently. If a non-transmission-connected distribution system has a significant influence in terms of voltage, power flows or other electrical parameters for the representation of the transmission system's behavior it may be considered as part of the observability area. The structural information related to the observability area has to be provided by each DSO to the TSO and shall at least include the information listed in Art. 43 (3) SO GL with an update of the information at least every 6 months. Unless otherwise provided by the TSO, each DSO shall also provide its TSO with real-time data related to the observability area, that should at least include the information referred to in Art. 44 SO GL. Which additional data exchanges are needed to facilitate TSO-DSO coordination of redispatch, should be discussed further in the projects work package 5, on DSO-TSO cooperation.

## 5.1. Structural Data

Master data for grid security analysis concerns any data which changes infrequently and is not represented by timeseries. The exchange of structural data within the SO GL is covered in Art. 43 - between TSOs and DSOs, Art. 45 - between relevant transmission connected SGUs and TSOs, Art. 48 - between TSOs, DSOs and distribution connected power generating modules and Art. 52 - between TSOs and transmission connected demand facilities. Art. 53 describes the data exchange between TSOs and distribution connected demand facilities.

According to Art. 51 (1) SO GL *“Unless otherwise provided by the TSO, each DSO shall provide to its TSO the information specified in Articles 48, 49 and 50 [structural data, schedules and real-time data of distribution-connected power generating modules] with the frequency and level of detail requested by the TSO. Each TSO shall make available to the DSO, to whose distribution system SGUs are connected, the information specified in Articles 48, 49 and 50 as requested by the DSO.”* Furthermore, according to Article 51 (3) SO GL, *“a TSO may request further data from a power generating facility owner of a power generating module which is a SGU connected to the distribution system, if it is necessary for the operational security analysis and for the validation of models”*. This means that DSOs are obliged to deliver all data of power generating SGUs, that are relevant for the TSOs security analysis, to the TSO.

**Data exchange between TSO and DSOs**

According to Art. 43 SO GL, the master data that each DSO shall provide to the TSO regarding its observability area[6] shall include at least:

*(a) substations by voltage*
*(b) lines that connect the substations referred to in (a)*
*(c) transformer from the substations referred to in (a)*
*(d) SGUs [(Significant Grid Users)]*
*(e) Reactors and capacitors connected to the substations referred to in (a)*

[6] Each TSO determines the observability area of the transmission-connected distribution systems, and if considered as significant in terms of voltage, power flows or other electrical parameters also non-transmission-connected distribution systems, to determine the system state, based on the methodology developed in accordance with Article 75.

**Data exchange between power generating facilities and TSOs/DSOs**

While the existence of SGUs within an area of a grid must be provided by the system operator to which the SGU is connected the information about the structural data in Art. 45 and 48 are an obligation of the significant generation facilities or in Art. 52 and 53 respectively of the significant demand facilities. The structural data relevant for redispatch concerns general data of the power plant, as well as installed capacity and primary energy source. For significant generation facilities, this data must be provided, independent of the size of a generation facility[7] or whether it is connected in the transmission or the distribution grid[8]. Significant generation facilities connected at the TSO level are also required by the SO GL to provide data to calculate the expected redispatch costs and Type D assets (see also Annex A) are also required to provide their lead times for activation.

The regulations for demand facilities contain a similar obligation, as TSO connected significant demand facilities must provide characteristics of the demand facility and distribution connected demand facilities must provide a structural minimum and maximum active power available for demand response and a minimum duration of usage.

In national law these requirements are implemented and complemented by Art. 5 of SOGL Dataexchange-R, requiring significant generation facilities to provide their point of grid connection, address, geographic location and maximum power at the point of grid connection.

Art. 11 of the SOGL Dataexchange-R complements the national implementation for significant demand facilities and lists the same requirement to provide the grid connection point, address and geographic location and maximum power at the point of grid connection.

While this gives the TSO and DSOs the necessary data to perform grid security analysis and consider significant grid users in their redispatch calculation, it appears that distribution connected demand facilities and demand facilities that provide demand response with an installed capacity below 25 MW are currently not covered by the detailing of the national data exchange requirements for structural data and a redispatch platform would need to obtain such data by other means.

## 5.2. Schedule

Grid topology, schedules and load forecasts are the main inputs for grid security calculation. Thus, TSOs and DSOs need this data to perform their obligations. Unlike structural data, scheduling is not only regulated by the SO GL and the SOGL Dataexchange-R but the "SoMa Schedules" (formally chapter 3) also defines the national scheduling standards and obligations to participate. Unlike SO GL and SOGL Dataexchange-R, which constitute legislative acts binding upon all persons within their scope of application, the SoMa does not constitute a legal act. Their binding effect vis a vis producers/consumers stems from the fact that they are declared as binding in the grid connection agreements concluded with TSOs/DSOs. The SoMa serve to operationalise data provision of Austrian market participants in a standardised manner. Currently an update of the SoMa is being drafted. Because of this the description within this text can only cover the current "SoMa Schedules" as of September 2022 but does not contain possible changes included within the next SoMa update.

Art. 46 – for units of type B, C, D (compare Annex A) – and 49 – providers of redispatching – of the SO GL, define the power generating SGUs' responsibilities to deliver schedules to the TSO and, in case of connection to the distribution grid, to the relevant DSO. Other than the information to the DSO no distinction is made between the obligations of TSO and DSO connected generation facilities and all facilities covered by these articles are required to provide schedules for active power output on a day-ahead and intra-day basis, unavailability schedules and active power restrictions.

[7] SO GL Art. 45 (1)(a), SO GL Art. 45(2)(a)

[8] SO GL Art. 48 (1)(a)

The obligation to provide schedules is reflected in Art. 7 of the SOGL Dataexchange-R. According to SOGL Dataexchange-R, all significant power generating grid users with an installed capacity of at least 1 MW must deliver schedules to the TSO, the relevant DSOs for a week-ahead, day-ahead and intraday timeframe for every metering point. It further requires all power generating grid users with an installed power of at least 1 MW to deliver an availability schedule for the year-ahead, week-ahead, day-ahead and intraday timeframe for every metering point. These schedules must include at least the available power with the granularity of 15-minute intervals.

According to “SoMa Schedules”, schedules contain the planned generation (power in MW) per 15-minute-interval, as described in Section 1.2. Schedules are required for the calculation of load flows and for network security analysis of the Control Area Operator and network operators. According to Section 2.3.4 of the “SoMa Schedules”, schedule data of power plants per power plant unit and pump storage connected to the grid levels 1 and 3 (greater/equal to 110kV) and plants with a capacity greater or equal to 25 MW are needed. Power plants connected to a grid level below 3 and with a total capacity smaller than 25 MW are also obliged to deliver schedules if these are necessary for the Control Area Operator’s or network operators’ security analysis. This enables the Control Area Operator to request schedules from other generation facilities providing redispatch. According to “SoMa Schedules” producers and balancing responsible parties (BRPs) may request to deliver aggregated schedules per plant instead of per power plant unit. If the Control Area Operator does not gain a significant additional benefit from receiving schedules per unit, a suitable aggregation may be arranged.

Schedules must be submitted by 14:30 for the following day to the central database of the Control Area Operator. Changes to the schedule are possible at any time. In the event of deviations from the schedule greater than 25 MW or greater than 20 % of the installed power the affected Control Area Operator and the system operators must be notified immediately, i.e. the adapted schedules must be sent immediately if one of the above-mentioned requirements is met. The exception is made for plants that participate in balancing energy. If plants particate in the provision of balancing energy the announcement of the planned feed-in is sufficient. A change in schedule due to the failure of a power plant unit must be communicated to the Control Area Operator immediately. If the failure results in a change to the schedule greater than 100 MW, the Control Area Operator (control room) must be contacted via phone. In general, deviations from the final submitted schedule are not allowed. However, currently there is no defined threshold for schedule quality and no penalties are in place for deviations from the final schedule.

In addition to active power schedules, power availability schedules must be provided. The provision of availability schedules is described in section 2.3.5 “SoMa Schedules”. The availability schedule provides information about an asset's availability. Announcement of availability is obligatory for the same parties as schedule announcement is. The timeframes, however, are different. Availability schedules, also known as PAS (Production Availability Schedule), are announced first Year-Ahead on the first of August for the following year and then week-ahead every Thursday at 8:00 AM for Friday of the same week until Sunday of the following week. One hour after any change in availability to the announced PAS is known, a PAS update must be sent if the change in available power is greater/equal to 25 MW, the change in lead time is grater/equal to 12 hours or the change in lead time to a new value is between 0 and 12 hours. PAS schedules consist of the lead time required to consider the max. power, the power, that is not available, the available power (upper limit) as well as the minimal power (lower limit) per hour. Art. 6 SOGL Dataexchange-R further establishes a data point with the information “available”, “not-available” and “test-operation”.

Neither the Regulation (EU) 2017/1485 (SO GL), “SoMa Schedules” nor SOGL Dataexchange-R currently regulate scheduling responsibilities for all demand facilities. Art. 52 (2a) SO GL, however, determines that transmission-connected demand facilities (SGUs) have to deliver schedules to the TSO. According to Article 52 (2c) and 53 (2a) demand facilities participating in demand response shall provide their minimum and maximum power available for demand response.

In conclusion, power generation SGUs (grid level ≥ 3 and installed capacity ≥ 25 MW or as required by the TSO) must deliver generation schedules according to SoMa that must be submitted by 14:30 day-ahead and contain the planned generation per 15 minute-interval per unit. The SOGL Dataexchange-R furthermore regulates that power generating SGUs with a capacity greater than or equal to 1 MW shall deliver generation schedules for a week-ahead, day-ahead and intraday timeframe per 15 minute-interval per metering point. Since the requirement of the SoMa is more specific, a generation schedule with a 15 minute-interval per unit shall be the general requirement and an aggregated schedule may be delivered with the condition stated in the SoMa.

PAS schedules are required for the year-ahead, week-ahead, day-ahead and intraday timeframe and defined in the SoMa as an hourly timeseries, whereas the definition of SOGL Dataexchange-R requires schedules with a granularity of 15 min. Further clarification on the granularity of the PAS schedule can be expected with the pending recast of the "SoMa Schedules".

Since schedules are required for transmission-connected demand facilities pursuant to Art. 52 (2a) SO GL without further national specification, the application of the details provided for generation schedules could be assumed. However, the limitations due to the definition of significant grid users in the SOGL Datenaustausch-V have to be considered. While schedule announcements by demand facilities are partially regulated on European level the definition of SGUs on national level is not sufficient and schedules are generally only listed as a necessity of generating units.

Since Art. 53 SO GL is also limited to introducing the requirement of forecasts of the available demand response potential of distribution connected demand facilities participating in demand response, subject to the decision of the relevant TSO, potential further regulations on schedule delivery of distribution-connected demand facilities (SGUs) would be helpful to harmonise participation in the redispatch process by generating and demand facilities both on national and international level.

## 5.3. Real-time data

Delivery of real-time data for significant grid users is required for system management and for monitoring the provision of system services. The provision of real-time data is defined in the SO GL Articles 44, 47, 50, 52 and 53. Articles 47 and 50 of the SO GL define data exchanges for power generating facilities (SGUs) connected to the transmission grid or the distribution grid. Both have to deliver real-time data on active and reactive power at the connection point or another point of interaction agreed with the TSO. Data exchanges between TSOs and demand facilities that are significant grid users are specified in Articles 52 and 53 of the SO GL.

The implementation of the international SO GL is realized by the Austrian "SOGL Dataexchange-R". Art. 9 of the SOGL Dataexchange-R obliges producers, that meet the requirements of Art. 9(1) SOGL Dataexchange-R to deliver the following real-time data to the TSO and relevant DSOs:

1. *Active power*
2. *Reactive power*
3. *Current and voltage*
4. *Position of switching devices >= 110 kV*
5. *Availability, if primary energy is wind energy*

According to Art. 11 (2) of "SOGL Dataexchange-R " significant demand facilities as defined in Art. 3 (4) must deliver the following real-time data for each metering point to the TSO and to the connecting system operator:

1. *Active power*
2. *Reactive power*
3. *Current and voltage*
4. *Position of switching devices >= 110 kV*

This obligation does not include demand facilities that provide demand response with an installed capacity < 25 MW, if they are connected to the grid at a voltage level below 110 kV. Aggregated redispatch providing assets, that would be part of the SGU definition in Art. 2 SO GL, are also not considered in the requirements defined in the national SOGL Datenaustausch-V.

# 6. Additional rules due grid connection requirements

All users of the electricity grid are bound by a set of regulations, defining how they may use their grid connection, possible usage constraints, which technical parameters they need to fulfil and which services they must provide to the TSO/DSO. The following section presents an overview of those regulations and how those regulations could affect the provision of redispatch by DSO connected generation and demand facilities. Regulations which do not affect the provision of redispatch are outside the scope of this project and are not part of this section.

The main documents specifying these regulations are, the ElWOG, the connection agreements with DSOs, RfG, NC DCC and TOR.

**Grid connection requirements**

When connecting to an electric grid, the generation or demand facility must request access to the electricity grid from the relevant DSO and acknowledge the general terms and conditions (GER: "Netzanschlussbedingungen"). This practice shall ensure that all parties that wish to use the electric grid may use the grid without discrimination. According to Art. 59(7) Directive (EU) 2019/944 (Electricity Directive), the regulatory authorities are responsible for *"fixing or approving […] at least the national methodologies used to calculate or establish the terms and conditions"* for *"connection and access to national networks"*. The main national regulation for this practice comes from the ElWOG 2010 in which, Art. 17(1) regulates, that *"[t]he conditions for access to the grid must not be discriminatory. They must not contain abusive practices or unjustified restrictions and must not jeopardize security of supply and quality of service."*[9] Furthermore, it is regulated in Art. 17 (3) ElWOG that the general requirements for grid connection have to include inter alia

- *"the rights and obligations of the contracting parties, in particular to comply with the Other Market Rules;*
- *[…]*
- *the minimum technical requirements for network access*
- *[…]*
- *the notifciation of planned supply interruptions;*
- *[…]*
- *the procedure and modalities for requests for network access;"*

The terms and conditions for connection to a DSO grid can usually be found on the DSOs website and they do not contain provisions which would inhibit the provision of redispatch. However, grid users must consider whether they have concluded individual agreements concerning an interruptible connection to the grid which could interfere with the provision of redispatch. It also should be mentioned that all grid connection contracts generally guarantee grid access while the grid is in the normal state.

In recent years, additional regulations were passed on EU level in the form of two network codes, Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators (NC RfG) and Regulation (EU) 2016/1388 establishing a Network Code on Demand Connection (NC DCC).

Regulation (EU) 2016/631 (**NC RfG**) describes requirements for the connection of new power generation modules to electricity grids and if existing power generation modules are being modified. These requirements increase with the size of the generation modules. Generation modules are categorized in types by size and the voltage level of the connection point ranging from type A (above 0,8 kW, below 110kV) to type D (above 75 MW, above 110 kV). The limits for all four types are included in Annex A. The NC RfG focuses on technical requirements and characteristics that include, but are not limited to, frequency stability, fault-ride-through, system restoration, protection schemes, island operation and black start. The requirements within the RfG enable and support secure system operation. The

[9] translated by the author

requirements however do not affect the provision of redispatch. In addition to the international regulation generation modules are also bound to comply with the national TOR [21]. These national technical and organizational rules are similarly structured by the categories provided in NC RfG.

Regulation 2016/1388 (**NC DCC**) contains requirements for new demand facilities and distribution facilities with transmission system connection. Similar to the RfG this includes requirements for frequency stability, voltage stability, short-circuit withstand capability, reactive power, protection, control, demand disconnection and demand reconnection, power quality, information exchange and simulation models. Especially relevant Articles for the provision of redispatch by a demand facility are Art. 27 to 33. Art. 27 specifies different kinds of demand response services that a demand facility may supply and Art. 28 details a set of minimum requirements for demand units that are used to provide transmission constraint management services to system operators. Art. 28 (2)(h) requires that, once a modification of power has taken place, the demand used to achieve this modification may only be modified if requested by the relevant system operator, i.e., the demand response must take place at the specified asset and the energy can't be resold. Concerning the connection of demand units, Art. 31-33 NC DCC specify the basic principles concerning the operational notification procedure. According to Art. 31 NC DCC the operational notification procedure for demand units that are used to provide DR services. Each demand facility owner has to confirm the ability of the facility to satisfy the technical design and operational requirements set in Title III of NC DCC.

In Austria, the technical and organizational rules for grids and demand (GER: "**TOR Netze und Lasten**"), published by E-Control, specify the requirements for grids and loads with transmission system connection. By accepting the conditions for grid connection to their system operator the demand facilities also agree to adhere to these technical requirements. The document contains requirements for frequency control, voltage stability, short-circuit capability, reactive power requirements, grid management, grid protection and grid rehabilitation. It is stated that DSOs and network users shall ensure that their network connection does not lead to inadmissible system perturbation. After the description of general requirements, the second chapter of "TOR Netze und Lasten" describes the requirements for demand modules connected to the transmission system which provide demand response services. For P/Q regulation services this is a minimum set of the following requirements:

- in accordance with chapter 11.1.1 fully functioning within a certain frequency band
- in accordance with chapter 11.1.2. fully functioning within a certain voltage band
- in accordance with chapter 11.1.3 ability to adjust their demand and have the necessary tools to communicate requests to/from the TSO

These requirements must be fulfilled by the provider of demand response services and ability to adhere to these requirements must be proven according to Article 12 before operating demand response services. Any providers of the demand response services must therefore check their compliance with TOR Netze und Lasten Chapter 2 before offering demand response service to the TSO or DSOs.

Currently a new Framework Guideline for demand response is being drafted by ACER and has been open for public consultation from 1st of June 2022 until 12th of August 2022 [35]. How the final framework guideline is reflected in the creation of new network codes or the amendment of existing network codes remains to be seen.

In Austria, it is possible to provide flexibility via interruptible tariffs. The following definition can be found in Art. 2 (1)(13) SNE-V: "*'interruptible' means the price rate for consumers for which the system operator is entitled and technically able to interrupt the use of the network at any time or at contractually predetermined times*[10]".

[10] Translated by the author

Interruptible network customers pay a lower network charge and, in return, offer the network operator the option of disconnecting the generator or consumer. The interruption signals must follow transparent criteria based on local needs and may not exceed a certain interruption duration (e.g., per year). In addition, the information about the interruption must be transmitted to customers, suppliers and other market participants (e.g. aggregators for demand side management) in advance, if required.

In the special case of electricity generation facilities that are integrated into the grid of industrial facilities and grid users, - operators of industrial facilities and relevant system operators whose grid is connected to the grid of an industrial facility, Art. 5 NC DCC regulates that it is possible to define conditions for disconnecting these generation facilities from the grid of the relevant system operator. The exertion of this disconnection shall happen in coordination with the relevant TSO. In Austria, this approach is also suggested in “TOR Erzeuger” (type A) in section 2.3. Additionally, in “TOR Netze und Lasten” it is required that *"[i]f requested by a relevant TSO, grids and loads must be able to automatically disconnect from the grid at certain voltages."*

During the project, it was determined during the definition of the technical requirements for redispatch in Deliverable 3.3 chapter 3.1.8.2, that the same flexibility must not be sold twice, as to ensure that the activation of a flexibility also results in its intended consequences. That is, FSPs that already provide their flexibility via an interruptible tariff cannot sell the interruptible part of their consumption or infeed as redispatch as the service might be interrupted by the DSO which would negate the intended effect. Similar considerations must be made for assets with a P(U) regulation that causes large fluctuations in infeed or withdrawal relative to the intended volume of redispatch.

## 7. Procurement and Financial Compensation of Redispatch

The following section examines the financial aspects of redispatch provision.

The general responsibilities regarding redispatch in Austria, the regulatory framework for financial compensation of redispatch is defined nationally by Art. 23 and Art. 66 ElWOG and on European level by the CACM as well as Regulation (EU) 2019/943 (Electricity Regulation) and Directive (EU) 2019/944 (Electricity Directive).

The rules regarding financial compensation of redispatch are regulated on European level by the CACM and ROSC Methodology, governing when the information about the cost of a remedial action must be communicated between (i) TSOs and (ii) TSOs and the providers of redispatch. Art. 35 (5) CACM states that costs for redispatch shall be announced to the TSO before redispatch is carried out and that the compensation shall either be based on the prices in the relevant electricity markets and timeframes or the incurred costs and economic drawbacks, as also required by Art. 23 ElWOG. Since 2019, new requirements regarding the compensation model for redispatch have been introduced by Regulation 2019/943 (Electricity Regulation) and Directive (EU) 2019/944 (Electricity Directive). The Electricity Directive stipulates in Art. 40 (6) that *"*[transmission] *system operators, subject to approval by the regulatory authority, or the regulatory authority itself, shall, in a transparent and participatory process that includes all relevant system users and the distribution system operators, establish the specifications for the non-frequency ancillary services* [e.g. redispatch] *procured and, where appropriate, standardised market products for such services at least at national level."* However, this requirement has not been implemented into national law as of yet since [Begründung].

According to EU-Law, the default method for the procurement of redispatch is market-based procurement as stipulated in Art. 13 (2) Electricity Regulation. Non-market-based redispatching may only be used, where one of the conditions listed in Article 13 (3) Electricity Regulation is met.

Where no market-based model is utilised, the compensation for redispatching shall at least be equal to the higher of the following elements or a combination of both: (i) additional operating cost caused by the redispatching, or (ii) net revenues from the sale of electricity on the day-ahead market (Art. 13 (7) Electricity Regulation). This means that the Electricity Regulation theoretically enables all options for remuneration, i.e. cost-based, cost+[11] and market-based.

EU-Regulations have direct effect and, therefore in general, require no implementation on national level. Notwithstanding the direct effect of EU-Regulations, national implementation may still be required if it is required by the regulation itself or in order to operationalise a requirement (commonly referred to as "limping regulation"; GER: *hinkende Verordnung*). This is the case with Art. 13 Electricity Regulation as it requires Member States to adopt a regulatory framework regarding redispatch, which complies with the requirements as set forth in Art. 13 Electricity Regulation.

Austria implemented a cost-based approach for the procurement of redispatch and distinguishes two cases: (i) Changes in power generation or consumption for providers that have entered into contracts with the Control Area Operator and (ii) changes in power generation or consumption for grid users that do not currently have a contract with the Control Area Operator.

The first case is described in Art. 23 (2)(5) ElWOG, which requires the Control Area Operator to conclude contracts with generators and consumers. Remuneration of these redispatch providers is based on the incurred economic disadvantages and costs.

In the second case, the Control Area Operator may order any generating unit to change its infeed in so far as no generating unit, which concluded a contract for the provision of redispatch is available in accordance with Art. 23 (9) ElWOG. In this case, the appropriate costs and economic disadvantages as the benchmark for remuneration must be

[11] Cost+, within the context of this text describes and remuneration model that is based on the cost incurred by the provider of redispatch but provides for an additional profit component to incentivize participation in redispatch.

determined by the national regulatory authority according to the principles of the NEP-VO. From these two cases it may be derived that Austria applies a cost-based remuneration scheme for redispatch. A list of possible costs was included in the Annex of Deliverable 3.3. Hence, Austria deviates from market-based procurement of redispatch as the default procurement mechanism as foreseen in Art. 13 (3) Electricity Regulation, since only the incurred cost may be remunerated.

In the following the exemptions from market-based procurement of redispatch as contained in Art. 13 (3) Electricity Regulation are listed.

Concerning exemptions from market-based procurement, Article 13 (3) Electricity Regulation states, that

*"Non-market-based redispatching of generation, energy storage and demand response may only be used where:*

*(a) no market-based alternative is available;*
*(b) all available market-based resources have been used;*
*(c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or*
*(d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8)."*

A derogation from market-based redispatch procurement may thus be warranted pursuant to these cases. Exemptions (a) and (b) are directed at the use of non-market based redispatch in specific situations with low market-based availability. This applies in cases when no market-based options are available. In these cases, a mechanism as stipulated in Art. 23 (9) ElWOG, which allows the Control Area Operator to direct producers to change their feed-in in case contracted redispatch resources are insufficient may still be necessary to ensure that all congestions can be relieved at all times.

The application of exemptions (c) and (d), on the other hand, is not aimed at situations in which there is no availability of market-based resources. The scope of application of exemptions (c) and (d) is determined based on possible shortcomings if market-based procurement should be implemented. If the liquidity in a potential market is too low to enable competition exemption (c) would apply. Strategic bidding, enabled by high predictability of congestions, is covered by exception (d).

As has been already stated, market-based procurement of redispatch is currently not in place in Austria. From the reference to Art. 13 Electricity Regulation contained in Art. 23 (2)(5) ElWOG, it may be concluded that the Austrian legislator has been aware of the requirements of Art. 13 Electricity Regulation (market-based procurement of redispatch as the base case). Therefore, it may be assumed that the Austrian legislator relies on one of the exemptions as contained in Art. 13 (2) Electricity Regulation. Naturally, in the case of Art. 23 (2)(5) ElWOG, only exemptions (c) and (d) may apply. Further guidance on whether the conditions for application of the exemption are still valid and whether the regulatory framework should evolve to implementing market-based procurement of redispatch may be provided by the NRA's report in accordance with Art 40 (5) of Directive 2019/944 (Electricity Directive). In this report, the NRA may assess whether a market-based model is economically efficient or a non-market-based model should be used. This requirement has not been implemented in Austrian law as of yet. It is also closely linked to the requirement in Art. 13 (4) of Regulation 2019/943 (Electricity Regulation) which requires TSOs and DSOs to report to the NRA on the level of development and effectiveness of market-based redispatching and requires the NRA to submit this report to ACER. While a full analysis of market-based redispatching is outside the scope of this deliverable, Section 10.3.4 aims at a feasibility study of market based redispatching.

Should the mechanism be changed to a market-based procurement the current ElWOG would not allow the TSO to compensate the participants above their economic disadvantages and costs. Therefore, any market model beyond a cost-based model is a subject to the decisions of the Austrian regulatory authority (E-Control), to ensure the costs of redispatch are acknowledged and considered within the system charges, i.e. the TSO is compensated for its expenses, if such a model should be deployed.

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## 8. Checklists for technical requirements (D 3.3) and regulatory requirements

The technical requirements for the provision of redispatch were defined in D 3.3. and within the previous chapters of this document the regulatory requirements stemming from different legal texts were examined. After compiling both technical and legal requirements lists were made to check whether the regulatory requirements are fulfilled by the current implementation and the design for the future redispatch process, and if the design for the redispatch process lacks any regulatory support. Table 2 lists all the requirements identified in national and European regulations, compares them to the redispatch requirements documented in Deliverable D 3.3 and derives necessary adaptations. Table 3 lists redispatch requirements documented in Deliverable D 3.3, compares them to the requirements identified in national and international regulations and derives necessary adaptations.

**Sorted by regulatory requirements:**

| Regulatory Topic | Current Status (Compatible / partially compatible / not compatible) | Reason | Necessary adaptations of the national regulatory framework |
|---|---|---|---|
| **Definition of congestion management** | **partially compatible** | **The current definition of congestion management in Austria is used to avoid or eliminate congestions in the transmission system. While the national ElWOG does not contain a definition for DSO purposes, DSO redispatch is regulated in some federal ElWOGs but not in all of them** | **A national regulation for the definition and range of application for congestion management and redispatch in the distribution system is required.** |
| Obligation by Art. 17 EU 2019/944 (Electricity Directive) to enable the participation of aggregators in redispatching | compatible | Participation of aggregators that meet the participation requirements (especially min. bid size) can offer redispatch on the planned redispatch platform and are not precluded from offering redispatch. | NA |
| Control Area Operator's obligations according to Art. 23 ElWOG to conclude contracts | compatible | The terms and conditions for participating on the future redispatch platform form a legal contract. | NA |
| TSOs obligations according to Art. 13 Regulation (EU) 2019/943 (Electricity Regulation) to enable all technologies to offer redispatch services | partially compatible | All technologies will be able to participate on the platform, however (in the beginning) the asset size is restricted by technical limitations to 500 kW.<br>The current as well as the planned redispatch process are technology neutral. | NA |

| | | | |
|---|---|---|---|
| **TSOs' obligation by Art 13. Regulation (EU) 2019/943 (Electricity Regulation) to implement a market-based model to redispatch unless the clauses in Art. 13(3) apply** | **Partially compatible** | **Currently, Art. 13(3c) is applicable to the national situation and thus a market-based model is not mandatory. This may change in the future.** | **NA, decision about the compensation model is to be made by E-Control in accordance with Art. 40 of the Directive 2019/944 (Electricity Directive).**<br>**However, an adaption of the ElWOG regarding a possible market-based provision of redispatch could ensure legal safety for the TSO.** |
| TSOs' obligation by Art. 23 ElWOG and Art. 13 Regulation (EU) 2019/943 (Electricity Regulation) to activate renewables and CHP plants as a measure of last resort | Outside of project scope | Currently no mechanism to manage an order of technologies is planned. This is considered out of the scope of the project. Also, dependent on decision if market-based model is used | NA |
| TSOs obligation by the ROSC Methodology to share XRAs for the purpose of the CROSA | compatible | ROSC timings are considered and opportunity to consider DSOs' results as part of the preliminary assessment | NA |
| Member states' obligation by Art. 32(1) EU Directive 2019/944 (Electricity Directive) to allow and provide incentives to distribution system operators to procure flexibility services | compatible | Aim of the project is to also allow DSOs redispatch | Since this European regulatory is a directive the implementation into national law is necessary |
| DSOs' obligation by Art. 32(2) Directive (EU) 2019/944 (Electricity Directive) to introduce standardized market products for flexibility services to ensure non-discriminatory participation of all market participants | partially compatible | All technologies are able to participate on the platform, however (in the beginning) the asset size is restricted. | Since this European regulatory is a directive the implementation into national law is necessary |
| Technical units' obligation by Art. 66 (6) ElWOG to provide redispatch | compatible | Covers the obligation to conclude contracts. Doesn't invalidate the TSOs right to direct producers if required to solve grid congestions. A new platform for redispatch does not conflict with these requirements. | Regulation only applicable to producers. Whether the obligation of consumers is required is out of scope of the project |

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|---|---|---|---|
| Technical units' obligation by Art. 35 CACM to provide costs ex-ante | compatible | Bids (including price information) have to be submitted before the GCT/ the start of security analysis | NA |
| Art. 43 SO GL: definition of an observability area by the TSO, data delivery by the DSOs for the relevant area | compatible | Definition of observability areas is connected to the definition of the aggregation level. | NA |
| **Art. 33 of SO GL: all necessary data has to be provided to the TSO by transmission-connected DSOs and power generating SGUs** | **partially compatible** | **All data relevant for contingency analysis has to be provided by DSOs, and redispatch providers (I.e. consumers and producers)** | **Adoption of a corresponding regulation for consumers could be helpful** |
| Art. 51 SO GL: DSOs must exchange structural data, schedules and real-time data of power generation SGUs with the TSO | compatible | Regulation of data exchanges between DSOs and TSO is sufficient, because the data of demand facilities is directly delivered to the relevant parties (TSO and relevant DSOs) | NA |
| **Schedule information in accordance with SO GL, "SOMA Schedules" (formally chapter 3) and "SOGL Dataexchange-R"** | **partially compatible** | **Delivery of schedules by power generating significant grid users and transmission-connected demand facilities is defined** | **Adoption of a corresponding regulation for distribution-connected demand facilities could be helpful. Otherwise, such data must be part of the terms and conditions to participate on the redispatch platform** |
| Real-time data in accordance with SOGL Dataexchange-R and SO GL | compatible | Scheduling for power generating SGUs and transmission-connected demand facilities are defined, distribution-connected demand facilities are covered by SO GL. Real-time data is possibly not required for all technical units. | Clarification for the delivery of master data by demand facilities that provide demand response in accordance with Art. 27 DCC with an installed capacity smaller than 25 MW could be helpful. |

| | | | |
|---|---|---|---|
| **Master data in accordance with "SOGL Dataexchange-R"** | **partially compatible** | **Master data exchange between SGUs that are power generating facilities or demand facilities with an installed capacity of 25 MW, DSOs and TSO is regulated sufficiently.** | **Clarification for the delivery of master data by demand facilities that provide demand response in accordance with Art. 27 DCC with an installed capacity smaller than 25 MW could be helpful. Otherwise, such master-data must be requested by the common redispatch platform[12].** |
| **Definition of SGU as basis of data exchange responsibilities** | **partially compatible** | **While the SGU definition in the SO GL would be in line with the participation of industrial FSPs and virtual power plants, the definition in the SOGL Dataexchange-R comes with more limitations for consumers since they are limited to demand facilities that are connected to a grid level ≥110kV or provide demand response services in accordance with Art. 27 DCC and have an installed capacity ≥25 MW. In general, all potential redispatch providers are significant grid users independent of their size.** | **An adoption of the SGU Definition in national level to be identical to that in the SO GL would be sufficient.** |
| Grid connection requirements according to RfG-VO, DCC-VO and ElWOG (2010) | compatible | No adaptions needed | NA |

[12] The Redispatch Platform is a platform used to exchange redispatch bids between the flexibility service providers and transmission/distribution system operators. It also receives network capacities by the TSO/DSOs in order to prevent the activation of bids which are incompatible with secure system operation. Via the platform bids are activated by TSO and DSOs. The detailed configuration of the Redispatch Platform will be defined in WP5 and WP9 of the project Industry4Redispatch.

| | | | |
|---|---|---|---|
| Requirements by TOR Netze und Lasten and DCC in case consumption units connected to the transmission grid are used for provision of load control services | compatible | Providers of redispatch must check their ability to fulfil the requirements by TOR 'Netze und Lasten'. It is possible to contractually agree on requirements on an individual basis between TSO and asset. | NA |
| Requirements by Art. 59(7) Directive (EU) 2019/944 (Electricity Directive), to perform ancillary services in the most economic manner | compatible | TSO and DSO optimise RD measures in a coordinated way in order to find the most cost-efficient solution to relieve congestions | NA |
| Option by SNE-V to provide flexibility via interruptible tariffs | compatible | Disconnection via interruptable tarifs can be carried out either at any time or at contractually predetermined times. Interruptible network customers have already sold their flexibility and as a result pay a lower network charge. An interruptible load cannot offer bids on the platform in market time units where an interrupt is possible, since it has already sold its flexibility. | NA |
| Art. 35 CACM and Art. 23 ElWOG: compensation of incurred costs | open | Depending on cost model | Any reimbursement beyond a cost-based model requires at least coordination with E--Control and could require changes to ElWOG |
| Art. 13 Regulation (EU) 2019/943 (Electricity Regulation) market based/non-market-based | compatible | Every cost model is possible (non market-based models only if conditions listed in Art.13(3) are fulfilled) | NA |
| The regulatory authority determines in accordance with Art. 40 Directive (EU) 2019/944 (Electricity Directive) if a market-based model is effective | open | Decision by E-Control is pending | NA |

***Table 2: checklist sorted by regulatory requirements***

**Checklist sorted by technical requirements:**

| Topic | Status<br>Compatible / partially compatible / not compatible | Reason | Necessary adaptation to technical requirements or national legislation |
|---|---|---|---|
| Conditions of participation | partially compatible | All technologies can participate, but current technical feasibility requires restriction based on installed capacity | NA |
| Bid firmness | compatible | ROSC Methodology and CACM require the provision of redispatch potential and ex-ante submission of costs has to be provided before redispatch optimisation. | NA |
| Bid size | compatible | Similar to balancing | NA |
| Bid content | compatible | ROSC Methodology and CACM: Data/costs has to be provided before redispatch optimisation: Available XRAs and restrictions have to be known | NA |
| Aggregation | compatible | The possibility to aggregate assets fulfils the requirement of Art. 17 Directive (EU) 2019/944 (Electricity Directive) to enable participation of aggregators.<br>In addition, aggregated schedules per metering point are possible (“SoMa Schedules”). However, the calculation of RAIF for ROSC Methodology could prove difficult if the granularity of aggregation is too low. | Further discussions regarding granularity of aggregation will be needed after gaining initial experience. |
| Timings | compatible | Compatible with ROSC Methodology | NA |
| Bid Structure | compatible | Dependencies/Restrictions are considered in ROSC, however, not clear if linked bids can be considered/coordination necessary --> out of scope | NA |
| Catch-up/Anticipatory effects | compatible | Dependencies/Restrictions in ROSC, however, not clear if data can be considered in CROSA --> out of scope | NA |
| Quality criteria | compatible | SoMa schedule quality | Thresholds and consequences for deviations from schedule/RD schedule within SoMa could provide a better basis for grid security analysis. |

| | | | |
|---|---|---|---|
| Master data | compatible | Obligation to deliver master data defined for generation facilities and for demand facilities that are SGUs is sufficiently regulated within SO GL and SOGL Dataexchange-R. | NA |
| Schedules | partially compatible | Obligation to deliver schedules is only defined for injecting parties and transmission connected demand facilities that are SGUs | Implementation of a similar regulatory framework for distribution connected consumers as defines for injecting parties in the "SoMa Schedules" and the "SOGL Dataexchange-R" could be helpful. Otherwise, such a requirement could be included in the conditions of participation on the redispatch platform. |
| Real time data | partially compatible | Obligation to deliver real-time data in accordance with SOGL Dataexchange-R is sufficient for power generating units and demand facilities that are SGUs | NA |
| **Cost model** | **partially compatible** | **Regulation (EU) 2019/943 (Electricity Regulation) enables a cost-based model, a cost+ model and a market-based model. However, ElWOG enables only a cost-based model** | **Any reimbursement beyond a cost-based model requires at least coordination with E-Control and could require changes to ElWOG** |
| Grid fees | compatible | System charges caused by the redispatch measure are remunerated within a cost-based model, see also deliverable 3.3 chapter 3.3.2. This is not the case in a market-based model. | NA |
| Securing flexibility potential | compatible | No additional flexibility mechanism apart from the grid reserve is currently needed | Out of Scope/ compare Deliverable 3.3 |

***Table 3: checklist sorted by technical requirements***

**The following issues and suggestions for regulatory adaptations were identified:**

- The definition of congestion management of the ElWOG currently does not include a unified national definition for congestion management and redispatch services in distribution grids. Such a definition would be required to enable a redispatch platform across Austria for DSO Redispatch.
- Art. 33 of SO GL states that all necessary data relevant for the TSOs contingency analysis has to be provided to the TSO by transmission-connected DSOs and power generating SGUs. An extension to consumers/loads, that are SGUs could be helpful.
- Since the regulatory framework by SO GL, SOGL Dataexchange-R and SoMa only covers the regulation of schedule delivery by producers and loads, that are SGUs connected to the transmission grid, a similar regulation for distribution connected loads, that are SGUs, would support better grid security analysis and baselining of redispatch by demand response. Otherwise, the participation criteria for a redispatch platform should require appropriate schedule and baseline submissions by participating demand facilities.
- Furthermore, the Regulation (EU) 2019/943 (Electricity Regulation) enables a cost-based, a cost + markup as well as a market-based model under certain circumstances. Since the ElWOG currently only enables cost-based redispatch the implementation of any cost model beyond cost-based is subject to discussion with E-Control and/or adaptations to the ElWOG. This may change in the future. In accordance with Art. 40 (5) of the Electricity Directive the national regulatory authority is responsible for the evaluation of the economic efficiency of a market-based model for national implementation.

Furthermore, member states are obliged by Art. 32(1) Electricity Directive to allow and provide incentives to DSOs to procure flexibility services. Since this is a directive, it must be implemented into national law to be legally binding. However, since the project aims at the inclusion of DSOs into redispatch process, this is already addressed.

Another subject to be implemented into national law is the DSOs' obligation by Art. 32(2) Electricity Directive to introduce standardized market products for flexibility services to ensure non-discriminatory participation of all market participants. The redispatch requirements in D 3.3 define a standardised redispatch product and the processes defined aim at non-discriminatory participation on the redispatch platform. Currently, the restriction of the minimum asset size limits participation, but this limitation is applicable to all asset types and thus not discriminatory by nature. The processes defined shall ensure that not only the conditions of participation but also the selection process is transparent and non-discriminatory.

Considering the quality criteria for redispatch delivery and schedule quality defined in D 3.3, a specification of thresholds considering allowed deviation from delivered schedules as well as consequences in the event of violation of such a threshold by the SoMa would be helpful, but not necessary.

# 9. Country Overview of Regulatory Differences

Based on the regulatory analysis, the question remains as to which additional measures might be necessary for an efficient procurement of redispatch as well as to ensure sufficient availability of relevant resources. This chapter zeroes in on 12 European countries, comparing their approaches of redispatch procurement. The countries have been selected to give a comprehensive overview of the different procurement systems for redispatch in Europe.

The analysis shows which remuneration methods are applied, which additional measures and monitoring mechanisms are used, and what role the DSOs are assigned. The following countries were included in the comparative analysis: Belgium (BE), France (FR), Germany (DE), Greece (GR), Italy (IT), the Netherlands (NL), Norway (NO), Poland (PL), Spain (ES), Sweden (SE), Switzerland (CH) and the United Kingdom (GB).

## 9.1. Remuneration for participating in redispatching

The county analysis showed, specifically in FR, GR, NL, NO, ES, and CH, that 6 out of twelve countries use a form of market-based remuneration, another three (GB, IT, PL) apply a hybrid approach thus procuring some parts based on market prices and some based on the incurred costs. By comparing redispatch volumes and mechanisms it is notable that countries with low redispatch demand tend to opt for market-based procurement whereas countries with higher needs for redispatch have opted for a cost-based remuneration. However, there are also countries that procure redispatch based on incurred cost (e.g., BE, SE) although the required RD volume in the respective country is low, and some that have implemented market-based mechanisms even though the RD demand is comparably high (e.g., ES), see Table 4, Figure 1 and Figure 2 (Note that GR and CH are not represented in both Figures since no data is available. The same can be observed when looking at the total cost of redispatch per year, countries that face higher annual costs for redispatch tend to apply a cost-based remuneration whereas countries with lower costs predominantly implemented markets (again except of BE, SE and ES), see Figure 1 and Figure 2. The following section illustrates typical characteristics of both market based, hybrid and cost-based redispatch remuneration.

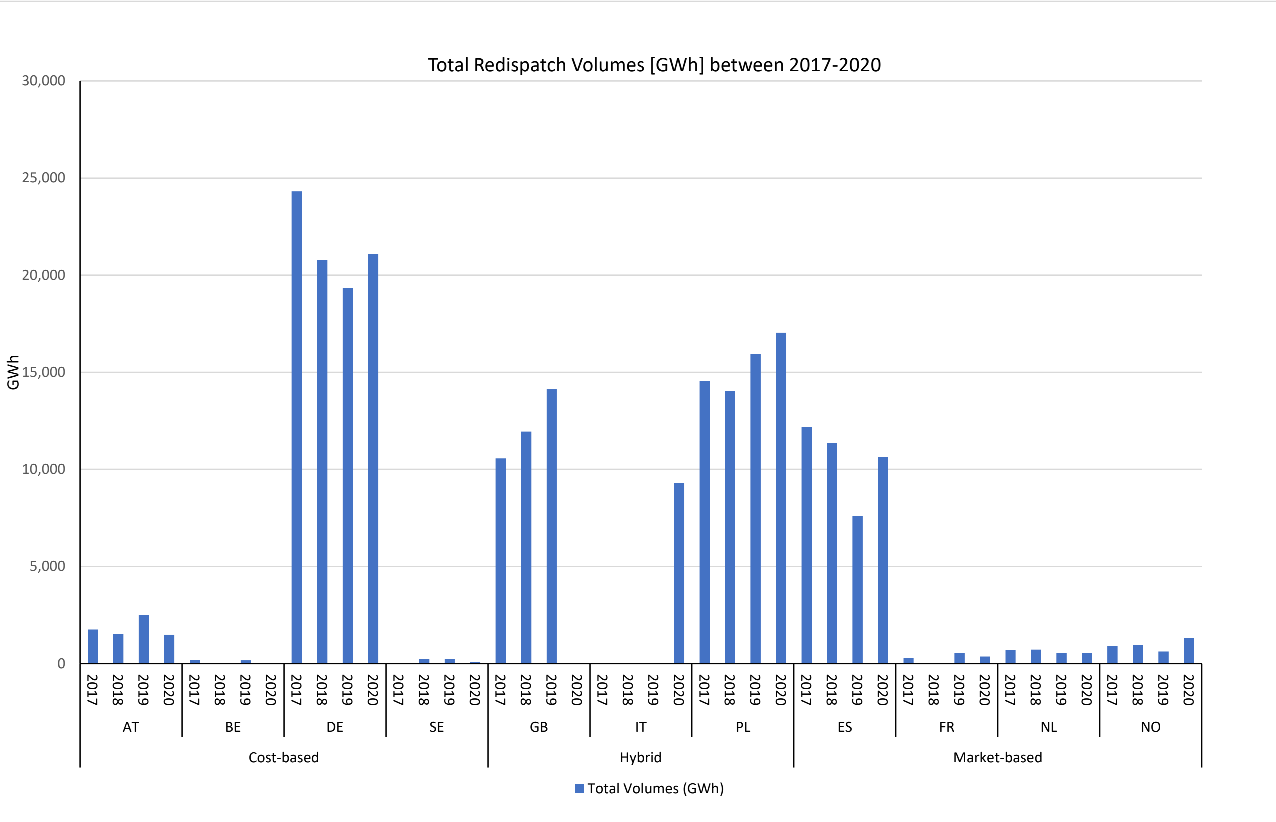


***Figure 1: Redispatch volumes based on ACER Market Monitoring Reports (Note that GR and CH are not represented since no data is available) [36]***

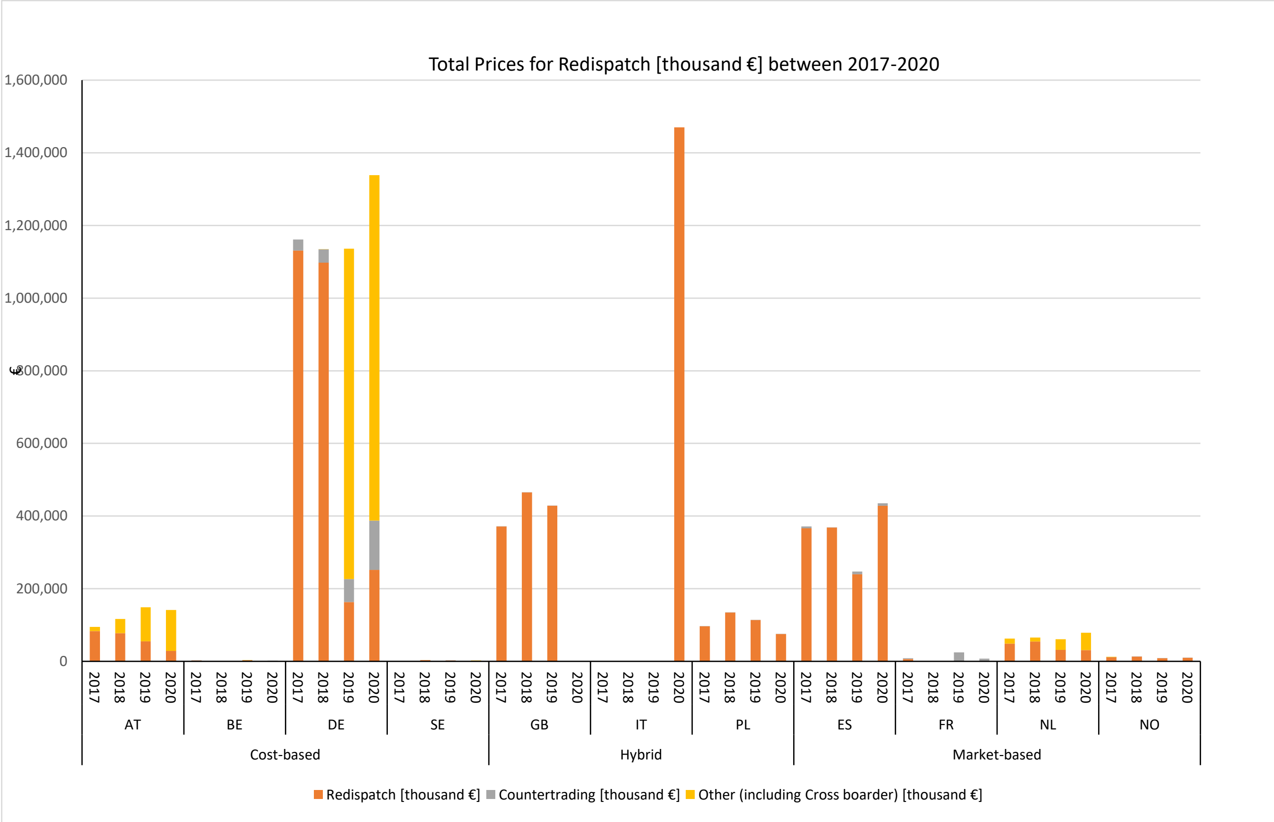


***Figure 2: Redispatch costs based on ACER Market Monitoring Reports (Note that GR and CH are not represented since no data is available) [36]***

### Market-based

Market-based redispatching is usually linked, in some form, to other electricity markets. Except for Norway, market-based redispatch is either procured in combination with the balancing market or bids for balancing reserve can also be used for redispatch or vice versa. The reason behind this linking is thought to be the intention to increase liquidity. Among the six countries that use market-based procurement, only three countries remunerate redispatch (or at least the bulk of redispatch) according to a market-based mechanism that is separate from the balancing procurement (NL, NO, ES), whereas the other three have a direct link to their balancing market. The former three countries have other measures in place to increase liquidity in the redispatch market [37], [38]. In the Netherlands, bids can be submitted for redispatch, balancing energy, or both, but can only be offered as redispatch bids if they include locational information [38], [39]. This should give market participants more flexibility to offer bids and at the same time increase liquidity in those markets. In Norway, redispatch is procured and traded exclusively through markets on the day of delivery.

All countries with market-based redispatch remunerate selected bids on a pay-as-bid basis (I.e., GR, FR, NL, NO, ES, CH).

**Cost Based**

Strictly cost-based approaches are deployed in Austria, Belgium, Germany and Sweden. However, there are also variations between those countries regarding which costs are covered. In Germany, for example, opportunity costs compared to other markets (i.e., intraday, balancing) are included. [40], [41] As an example, for costs that may be reimbursed, the following expenses are reimbursed in Germany:

- The necessary expenses for the adjustment of the feed-in (e.g., fuel costs).
- The consumption value of the plant for the actual adjustment of the feed-in.
- Proven lost opportunity costs, if these exceed the costs to be reimbursed by the first two points.
- Ramping costs or costs for postponed planned revisions.

In Belgium, providers for redispatch are allowed to place bids on other markets, regardless of the risk of creating further congestions, which is why no opportunity costs in this regard are reimbursed [40], [41]. Generally, demand facilities are included in the Belgian procurement system. In Germany, demand response is generally excluded from their compensation mechanism, but has been considered by a separated market mechanism for interruptible loads pursuant to the Regulation of Interruptible Loads “Verordnung zu abschaltbaren Lasten (AbLaV)”- which is expired since 01.07.2022 (see also chapter 9.2.) [42].

**Hybrid Mechanism**

Hybrid mechanisms describe a variety of different approaches that procure redispatch partially based on incurred cost combined with market-based remuneration mechanisms.

Such hybrid procurement is observable in GB, IT and PL. In Italy and Poland, solving congestions via redispatch measures is tightly meshed with their ancillary services in general. Some operations are based on market-based procured capacities, and some based on requested activations only remunerated according to their incurred costs. Those two countries thus claim that it is hard to identify how much their real total costs for redispatch are (I.e., the data given in Figure 2 for these countries are therefore difficult to compare with those of the other countries.) [38]. In Great Britain, redispatch gets procured in three different ways. (1) Large volumes get procured based on bilaterally negotiated cost-based contracts (up to nine weeks in advance). (2) Capacity gets procured based on market-based tender calls, before the day-ahead market clearing. (3) Small volumes are procured from their balancing mechanism if applicable [38], [37].

The design of the different hybrid models varies between the countries and needs to be adapted to the special needs of each country individually.

One advantage of the introduction of a hybrid model is the flexibility that such models provide. Therefore, a discussion of whether a hybrid model should be constructed for the usecase of Germany is currently in progress.

In the recent past, Germany further developed its RD mechanism with the introduction of the so-called ‘Redispatch 2.0’. The main motivation for this was the integration of feed-in management in planning value-based RD processes. With the introduction of minimum factors that guarantee that Renewable Energy (RE) and combined heat and power plants are last at shut-off, it was ensured that the RE feed-in priority remained in place. Furthermore, the RD 2.0 regime takes into account decentralized generation units and storages (>100 kW), as well as units that can be remotely controlled by a system operator. Although the RD potentials increased, a problem that still remained is the lack of sufficient positive RD potential in the south of Germany. A solution could be the inclusion of small demand-side units such as electric vehicles and heat pumps, of which due to the structure of the population, buildings and households, a large number is expected (especially in the west and in southern Germany). The problem is that the current cost-based RD regime does not allow the use of decentralized flexibility for RD. This is mainly due to the fact that the cost basis is often not clear or only available with a disproportionately high operational effort. Therefore, a German study conducted by ‘E-Bridge’ in collaboration with TransnetBW and TenneT, concludes that the existing, cost-based RD is unsuitable to integrate small-scale decentralized flexibilities and storage facilities into the RD regime. Instead, they propose a hybrid form of cost-based RD for conventional powerplants (that are already used in RD 2.0) and a marked-based approach for all other flexibilities. Both long-term capacity services and short-term energy bids shall be included in the RD 3.0 mechanism [43]. Participation in this complementary market-based mechanism should be on a voluntary basis. A non-discriminatory selection of all available potentials form both, the RD 2.0 and the RD 3.0 is ensured by a common merit order list (MOL) of all RD offers, whereby the supplementary market-based RD potentials are remunerated according to their offer prices (i.e., pay as bid).

It should be noted that the widely varying approaches for market-based, hybrid and cost-based redispatch procurement involve the implementation of several accompanying measures or complementary procurement mechanisms, which will be outlined in chapter 9.2., [45].

Generally, most of the remuneration methods, whether cost-based, market-based or hybrid, have been implemented in the last few years (except for IT and SE) or are currently being reformed. This is due to new regulatory requirements on the European level, as well as the increasing need for congestion management.

Furthermore, it is important to notice that the remuneration of redispatch is very complex, as country-specific characteristics, such as the used technology mix, network topology as well as characteristics of existing markets, strongly influence the establishment of efficient redispatch mechanisms and the accompanying remuneration methods. These different requirements make the adaptation of a general approach difficult. Therefore, many of the newly established systems are not yet mature but are still being evaluated and further developments cannot be ruled out.

## 9.2. Additional measures and obligations of grid users

Depending on how redispatch is procured, different requirements arise for the implementation of additional accompanying measures. In a market-based approach there is always the risk that market participants exhibit gaming behaviour, whereas a cost-based approach is based/dependent on obligations to participate. In both models, additional measures and regulations are needed to ensure sufficient redispatch resources and to monitor potential strategic bidding behaviour.

### 9.2.1. Increase liquidity

**Obligations to participate**

In order to ensure sufficient availability of redispatch potentials, some countries obligate producers to offer flexibilities or to report their available potentials (e.g., BE, FR, DE, IT, NO, PL, SE, ES). This applies mostly to plants above a specific generation capacity, but also in some cases to type-specific plants (e.g., pumped storages in BE). In countries with cost-based regimes power plants must be obliged to offer redispatch, otherwise there is no incentive to participate in the redispatch mechanism. However, also within countries that apply market-based procurement, obligations to bid or mandatory participation to provide available capacities are present.

In France, Norway and Poland, obligated plants primarily place regular bids for redispatch and are only forced to provide additional flexibilities in the event of insufficient offers, in contrast to the mandatory participation of all available capacities in other countries (BE, DE, IT, SE, ES).

In case of insufficient availability of redispatch bids in FR, IT, NO, PL and ES, the necessary quantity is requested on a mandatory basis and only the incurred costs are reimbursed (in Norway by the prevailing day-ahead price). This incentivises suppliers to place bids like an impending penalty payment would, due to the resulting lack of profits in case of cost-based remuneration [37], [38], [46]. In Italy and Spain, such obligations concern specific balancing energy offers (FCR in Italy and mFRR in Spain), which may also be used for redispatch. In Spain, those offers for mFRR are remunerated according to the usual market rules (i.e., their tertiary balancing market). In Italy, FCR bids are only compensated by their incurred costs [38], [47].

**Integration with other services**

Generally, the integration of redispatch to the balancing market is an approach taken to increase the liquidity and the availability of assets in advance. To further increase availability of resources for redispatch, some countries have opted for the integration of demand response. Nevertheless, in order to ensure industry participation, additional incentive mechanisms are needed:

In some of the countries, industries can participate in the existing redispatch procurement mechanism voluntarily whereas in others separate auction platforms are implemented to remunerate such assets. The latter can be found in France, Germany Greece and Spain (i.e., “Appel d’Offre Effacement”, Auctions for interruptible loads (AbLaV), Interruptility Service, Interruptibility Scheme, respectively). In these countries, the TSO is allowed to directly control the energy consumption of industries downward, based on contracts awarded through auctions. In Germany, the provision of such a service is remunerated with a capacity price. In case of actual reduction of load, the affected parties receive an additional energy price payment. Those prices are determined through weekly auctions by the TSO and are capped at 500 €/MW/week for the capacity price and 400 €/MWh for the energy price [42]. In Greece, direct control of loads is remunerated by contracted fixed tariffs determined through three-monthly auctions where the maximum auction clearing prices are 45000€/MW/year and 65000€/MW/year for the two segments, respectively, for up to 48 hours and 1 hour interruption[13] [48]. In Spain, interruptible loads are procured according to reverse auctions in which the starting price for each block of capacity product is reduced until only one bidder remains[14]. The opening price starts at 125000 €/MW/year for 5 MW capacity products [49]. This service is also in competition with their balancing regulation scheme for mFRR and only gets activated if its costs are cheaper than the cost of tertiary reserves. In Poland and Sweden such agreements are only available through bilateral negotiations [37], [50].

**Bilateral Contracts**

In general, the use of additional bilateral contracts is a measure that is applied in various ways. In Poland, there are additional long-term contracts to secure generation from power plants that are required due to the network topology (must-run contracts) [37]. In the UK, as mentioned in chapter 9.1, large volumes of redispatch are also procured through the negotiation of bilateral contracts, whereas smaller units are procured through their balancing market. These negotiations often start nine weeks in advance and may also be conducted close to real time [38]. In Greece and Sweden, the DSOs are allowed to sign contracts with potential redispatch providers to some extent, to procure flexibilities (see in more detail chapter 9.3.) [50].

### 9.2.2. Mitigate gaming strategies

A risk of market-based redispatch is that market participants would benefit from excessive prices by exerting gaming strategies. Market-based procurement of redispatch bears the risk of relevant power plants being in a position to exercise local market power, in particular where a congestion is structural (i.e., frequent and predictable) [51], [52]. But the risk of gaming is always present if either the liquidity level is low and/or market participants are able to predict the need for redispatch, including that they are aware of the opportunity to create congestion on purpose by them self (in order to achieve extra profits from redispatch). In such cases, distorted price signals could result from these markets due to strategical bidding behaviour of market participants (e.g., Inc-dec Gaming[15] see also 10.3.3) [53].

In order to prevent inc-dec gaming the establishment of a market design, that enables the integration of the maximum potentials for redispatch, to increase the liquidity, is vital. For that reason, all countries that implemented

[13] Only consumers >400 MW that are connected to the transmission grid are included.

[14] A reversed auction is the opposite to a conventional auction, that is, the supplier who offers a bid with the lowest price wins the auction. The products are predefined capacity products.

[15] A bidder’s strategy which involves increasing the bid volume in the first market (commonly, the day-ahead market) in the expectation of congestion only to decrease it in the subsequent redispatch market, profiting in both markets as a result [53]. Also see chapter 10.3.3.

market-based redispatch linked its procurement to existing market schemes, i.e., balancing markets or intraday (in FR, GR, IT, NL, NO, PL, ES, CH, GB). Another possibility to increase the liquidity is the inclusion of demand response (in FR, NL, NO, ES, PL, GR).

**Financial Penalties**

To further avoid the engagement in such gaming strategies some countries have also introduced additional measures to counteract excessive pricing [53]. In the Netherlands, Norway and Great Britain, the regulatory authorities are entitled to intervene and may further charge fines if such actions on bidder's part are identified. In the UK, the so-called Transmission Constraint License Condition (TCLC) mechanism aims at detecting excessive pricing by comparing actual prices to pre-determined reference prices[16] [54]. If such excessive pricing is identified, the provider in question may be subject to a financial penalty.

**Price caps and cost-based procurement as a backup solution**

In Norway, the TSO is entitled to accept a bid without paying the related offered price under specific conditions. Those conditions are met if there is only one or a few relevant assets that are able solve the congestion and the offers are clearly not reflecting true costs. More specifically, if the prices are higher by an average of 19.5% than the usual marginal costs of the technology involved for that time period, the TSO has the right to withhold from paying the offered price (instead the prevailing price from the day-ahead market is applied). If this happens frequently, the flexibility provider is charged with an additional fine [46]. In essence, this regulation can also be understood as a simple (dynamic) price cap. A price cap is also implemented in Italy, where the maximum bid cannot exceed 3000 €/MWh.

**Market design choices**

Norway and the UK attempt to prevent undesirable behavior by ex-post controlling activities whereas the Netherlands attempts to achieve the same goal through ex-ante mitigation measurements. In order to avoid gaming, the Dutch TSO introduced the following requirements: (1) a minimum of three competing market participants (including the participation of demand response and storage) and (2) additional interventions in the case of suspicious bids (this may result in splitting up bidding-zones or a fine[17]) [55].

Splitting bidding zones, as mentioned above, can also be considered a supplementary measure. It can reduce the need for redispatch in advance if structural, physical bottlenecks are modelled more accurately. However, this also has an impact on the liquidity and prices on spot markets. Furthermore, bidding zone configuration is not an issue in every country, hence the splitting of bidding zones is not always effective. Furthermore, splitting of bidding zones could also result in opposite effects, e.g., reducing market liquidity or increasing the risk of creating market power.

Another mitigation measure is the negotiation of long-term contracts (in GB, GR, SE). They are not only applied to ensure the availability of assets, but also to avoid market parties exerting excessive price strategies. For example, if a participant has market power or is in the position of being the only one to provide critically needed volumes. In such a case it could be obvious to face strategical bidding behavior and the procurement based on a bilateral agreement may be preferable [55].

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[16] "Circumstance 1 of TCLC prohibits behaviors whereby an electricity generator (or affiliate) seeks to create or exacerbate a transmission constraint by dispatching or withholding one or more generation units in circumstances where" ... "the generator and its affiliates together have more economic options available to them and then enter into arrangements in the Balancing Mechanism (BM)." … "Circumstance 2 of TCLC prohibits electricity generators in reference to reducing generation from: (i) paying or seeking to pay the SO an excessively low amount or (ii) paying or seeking to be paid an excessive amount by the SO." [54]

[17] It does not elaborate on how the bid zone is divided and whether this is temporary or results in a permanent change.

## 9.3. DSOs' roles and responsibilities regarding redispatch (optional)

The approaches to procure redispatch increasingly involve more competences and participation of the DSOs regarding congestion management to achieve more efficient use of available flexibilities at all network levels. This is also addressed in some of the analyzed countries.

In Greece, the DSO is entitled procure flexibility from distributed energy resources (DER) for local grid management based on contracts. This foresees the possibility to conclude "Demand Control Contracts" with individual electricity consumers in network areas that are considered congested. Similar to the interruptability scheme mentioned in section 9.2, these contracts allow the DSO to limit and interrupt the supply for specified periods (financial compensation in this case is also based on standardized contracts). The DSO further has the right to directly request voltage control by absorbing/injecting reactive power or by curtailing active power from distributed generators, according to their connection agreement. In such a case, no additional compensation is provided [46].

In Spain, DSOs can direct DERs to solve congestion according to the same regulatory framework as the TSOs. However, DSOs can only act by instructing the TSO that then accesses the bids and calculates the necessary redispatch to solve the detected congestion. [46].

In Sweden, as mentioned above, the DSOs can procure flexibility from DERs through bilateral contracts. These contracts can include possibilities for the DSOs to increase power production and decrease load from big heat pumps, industries and datacenters at a one-hour notice [46].

In the Netherlands, the DSOs and the TSO are equally entitled to use the supply from their respective redispatch procurement systems to manage congestions. Germany is currently introducing the opportunity that the DSOs are able to register via contracts to participate in congestion management autonomously [41], [47].

In Belgium, the DSOs are currently not involved in congestion management, however, their integration to cooperate with the TSO to procure redispatch is planned but not specified yet [48].

## 9.4. Summary and recommendations

The analysis shows that six of the twelve analysed countries use a market-based RD remuneration mechanism, three a hybrid procurement approach and three use cost-based remuneration (see Table 4 below). The trend is towards market-based remuneration in Europe, which might be a result of Article 13 of the Regulation (EU) 2019/943 (Electricity Regulation) [3]. However, when comparing countries that use cost-based procurement with those that have implemented markets, it can be observed that in most cases the RD demand is much higher in countries without markets (except for Sweden and Belgium for cost-based remuneration and Spain for market-based remuneration), see Figure 1.

There is a variety of country specific characteristics that impact the establishment of market-based redispatch procurement which have a decisive influence on the decision on the remuneration method. In France, for example, the need for redispatching is considerably low and the TSO is able to apply network topology reconfiguration measures in order to solve most of the congestions. In Switzerland, most of the demand for redispatch originates from other countries like Germany and Italy. Switzerland therefore always relies on cross-border cooperation in order to solve congestions [56]. Norway, as the only country that established a stand-alone redispatch market, is considered as one of the most liquid electricity markets in the world [55]. However, also depending on these characteristics, additional different accompanying measures are required in order to either increase liquidity and/or prevent unintended strategic behaviour.

According to the results of the analysis, market-based procurement is almost always linked to established markets (predominantly to balancing markets, except in NL there it is also included to the intraday market). This is related to the efforts to increase liquidity via market design and thus reduce the incentive of engaging in gaming behavior. Some countries additionally introduced further measures to mitigate and/or detect such unintended strategic behavior (e.g., the implementation of market monitoring to verify prohibited conduct). In the case of market power, no specific measures are taken to counteract this. Besides market-based procurement, some countries additionally procure redispatch according to negotiated bilateral contracts (in addition to their market-based procurement) an approach taken to effectively limit the impact of parties with market power. In general, not only cost-based procurement must obligate participants to offer their capacities, also within market-based mechanisms it seems crucial to some countries to oblige producers to offer flexibilities for redispatch to ensure sufficient participation to a certain extend.

An approach taken regardless of the prevailing remuneration mechanism is the integration of demand response. In market-based mechanisms this could increase liquidity and may consequently reduce prices and the risk of gaming. Cost-based approaches also benefit from the integration, due to the increased availability of resources which further increases the possibility of cheaper redispatch measures. Nevertheless, many of the analyzed countries established separate capacity markets to include demand response offers. These markets are still in competition with the other prevailing redispatch procurement approaches but get remunerated according to a separate mechanism. A more detailed explanation about why they are separated is not given and therefore uncertain, as other countries have been able to implement an integration of these sources into common mechanisms.

Considering hybrid procurement mechanisms seems to intend to procure market-based remunerated capacities for redispatch were possible, however, additional cost-based call schemes are implemented, indicating that there is the fear that purely market-based remuneration could increase socio-economic costs. Therefore, a hybrid approach can also be framed as a gaming mitigation measure, I.e., market-based remuneration gets only considered where it efficiently reduces the overall costs.

Another measure that is considered as beneficial for cost as well as market-based approaches is the participation of DSOs in procuring redispatch. “The European Commission estimated that the EU could save up to 5 billion Euro per year in avoided investments by 2030, if DSOs were able to solve local congestions through flexibility markets” [57]. However, in a few countries the DSOs are only partially integrated, but the trend seems to be to further improve their participation.

| Country | Market-/cost-based | Remuneration | Demand response | Linked to other markets | Participation of DSOs |
|---|---|---|---|---|---|
| **Belgium** | Cost-based | Based on incurred cost | Voluntarily and additionally by a capacity reservation market | Assets can be activated either for RD or BL (depending on the specific offer) | No, but is planned to get more included in the future. |
| **France** | Market-based | Pay-as-bid | Additional by a capacity reservation market | Together with balancing energy | N/A |
| **Germany** | Cost-based | Based on incurred cost | Additional by a capacity reservation market (planned) | Completely separated | Yes |
| **Great Britain** | Hybrid: Market-based/ Negotiated bilateral contracts | Big volumes by negotiation, small volumes by uniform pricing | N/A | Smaller units are procured together with balancing energy | N/A |
| **Greece** | Market-based | Pay-as-bid (currently!)* | By an additional "Interruptility Scheme" (only consumers >= 400 MW) | Together with balancing (currently!)* | Yes, they can procure DR by bilateral contract and by Connection Agreements |
| **Italy** | Hybrid | Pay-as-bid, and cost-based if based on a requested call | N/A | Yes, within one Dispatching Service Market, and together with balancing energy | N/A |
| **The Netherlands** | Market-based | Pay-as-bid | Yes (voluntarily) | Together with balancing, but get remunerated by a distinct merit order; Also, together within the intraday market | Yes, they can activate offers from the market autonomously |
| **Norway** | Market-based | Pay-as-bid | Yes (voluntarily) | Separated, but balancing energy offers may also be used for redispatch | N/A |
| **Poland** | Hybrid: Market-based with exceptions | Uniform pricing and sometime based pre-defined variable costs | By contracts (usually only large energy consumers) | Together with balancing energy | N/A |
| **Spain** | Market-based | Pay-as-bid | By an additional "Interruptility Scheme" | No, but additional reserves are called from a joint clearing process with tertiary energy | Yes, DSOs but only act by instructing the TSO. |
| **Sweden** | Cost-based | Based on incurred costs | Yes, by biliteral contracts with the DSO | Balancing Assets can be used for redispatch, but there is no joint procurement. | Yes, procuring DR and flex from DES |
| **Switzerland** | Market-based | Pay-as-bid | N/A | Together with mFRR | N/A |

***Table 4: Country overview***

| Market- or cost-based | Remuneration | Demand Response | Linked to other markets | Participation of DSOs |
|---|---|---|---|---|
| Market-based | Pay-as-bid | Integrated to the market | Linked to another market | Yes |
| Hybrid | Other | Both | Partially linked | To a certain extent |
| Cost-based | Based on incurred costs | Separated | Not linked to another market | No |

***Table 5: Legend to colour code of Table 4***

The findings are summarized in Table 4 to provide a better overview. In conclusion, the following recommendations can be stated based on the analysis of the countries studied:

- **There is a tendency for countries with low RD demand to employ market-based models**
- **It seems useful to link RD markets to other flexibility market in order to increase liquidity.**
- **The inclusion of small flexibility assets, that are not yet covered by the current redispatch regime, is beneficial regardless of the remuneration mechanism.** This should not only enable the use of flexibilities of industries for redispatch, but also for ancillary services in general.
- **Many countries included demand response via separated capacity markets.** In combination with a cost-based redispatch procurement, this mechanism can also be framed as a hybrid procurement method
- **A trend to increase the participation of DSOs to procure flexibilities for redispatch can be observed, yet their current scope of action is rather small.**
- **There is no country that remunerates their redispatch procurement based on a "cost+" model.** Some countries rely on market-based procurement, although their implemented markets design as well as their applied accompanying measures differ. Some just remunerate incurred costs and some will at least in the future apply mixed approaches, i.e., "hybrid procurement", however, there is no country remunerating incurred costs together with an additional compensation tariff, I.e., "cost+", to incentivize participation.
- **Market-based redispatch gets predominately remunerated pay-as-bid.**
- **Market-based remuneration should always be accompanied by certain measures to mitigate gaming behavior.** The choice of such countermeasures is strongly dependent on the country specific circumstances, but always refers to some sort of market monitoring processes. It seems that additional countermeasures are important to consider when introducing market-based procurement. Even Norway, as a country with one of the most liquid electricity markets in the world (see also [55]), implemented additional monitoring measures.

# 10. Regulatory adaptations

The regulatory analysis and comparison with the redispatch requirements developed in the projects Deliverable 3.3 has identified the following regulatory gaps which require adaptation:

- The roles and responsibilities regarding redispatch, attributed to the DSO are not defined within the national ElWOG and while some federal ElWOGs allow for DSO redispatch the legislation is not harmonised within Austria
- There is currently no obligation to exchange schedules for demand facilities, that are SGUs connected at the distribution level
- While the SGU definition in the SO GL would be in line with the participation of industrial FSPs and virtual power plants, the definition in the SOGL Dataexchange-R comes with more limitations. In general, all potential redispatch providers are significant grid users independent of their size. This should be reflected in the national definition of SGUs.
- Financial compensation of redispatch is limited to economic disadvantages and incurred costs by the national ElWOG

While the adaptations of some of the identified points above are straight forward, financial compensation requires a detailed analysis of possible adaptations and their effect on system security and socioeconomic costs.

## 10.1. The Definition of redispatch and DSOs obligations

As analysed in chapter 1 redispatch is defined in the Electricity Regulation. This European definition should be directly applicable and should not have to be transferred to national law. It concretely states that redispatch is a measure, that is activated by TSOs or DSOs. As redispatch is commonly used as a measure for congestion management, and the aim of this project is to relieve network congestions on different grid levels, we suggest extending the national definition of congestion management to applications at distribution grid level and to harmonise the congestion management obligations and responsibilities by the DSO across the federal ElWOGs.

This extension would go hand in hand with the topic of incentives for the use of flexibilities in the distribution network, which was discussed in chapter 4.2. It is required by EU legislation to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management, in order to improve efficiencies in the operation and development of the distribution system. Since this requirement is part of the Electricity Directive, the implementation into national law is necessary. For this implementation, the DSOs involved in the project propose to

- use analogue mechanisms in the distribution grids as used in the transmission grid,
- find definitions to clearly separate cases of congestions to be solved by redispatch and cases to be solved by the application of other flexibility options such as interruptible loads, dynamic grid tariffs or connection agreements.
- extend the European legislation when transposing the directive to national law by a clarification of the role of the regulatory authority regarding the incentives for the use of flexibilities in distribution networks and
- specify the term ‘economically efficient’ concerning the trade of between congestion management and investments in grid infrastructure.

## 10.2. Exchange of schedules concerning demand facilities and SGU definition

As elaborated in chapter 5.2, the SO GL only stipulates that generation facilities and transmission connected demand facilities that are SGUs are obliged to send schedules to the TSO. Within the Austrian SOGL Dataexchange-R (GER: SOGL Datenaustausch-V) significant demand facilities are defined as demand response providing assets above or equal to 25 MW and their exchange of schedules is currently not defined by the national regulation. Without schedule information the load must be forecasted by the TSO/DSO for grid security calculations and baselining can only be performed via actual measurement values and thus only for near real-time activation. As a result, such units could not be used for redispatch.

Here the requirement to transmit schedules to the TSO would have to be added to the obligations of distribution connected demand facilities with a similar wording to that of transmission connected demand facilities. Whether the distinction between the obligations of distribution connected demand SGUs that deliver redispatch and other distribution connected demand SGUs would be needed is open to discussion and out of the projects scope.

Such a requirement could either be added to the requirements for participation in redispatch by the TSO while it is not yet regulated by other texts or it could be included within SoMa. At the time of writing a new version of “SoMa Schedules” (GER: Sonstige Marktregeln Fahrpläne) is under consultation.

If the definition of schedules described in the SoMa would be adapted to cover schedules of demand facilities, especially those providing system services such as redispatch, the participation of demand facilities in day-ahead redispatch would be enabled.

Furthermore, clarification by the “SOGL Dataexchange-R" is needed, since it doesn't explicitly mention the obligation of demand facilities to announce schedules. Since the SOGL Dataexchange-R restricts the SGU definition by Art. 2. (1)(d) SOGL to significant demand facilities providing demand response directly to the TSO in accordance Art. 27 RfG with an installed capacity ≥ 25 MW, an adaptation of the definition in the SOGL Dataexchange-R would be required, in order to address redispatch providing demand facilities with an installed capacity below 25 MW.

## 10.3. Financial compensation of redispatch

The analysis in chapter 7 shows that Regulation (EU) 2019/943 (Electricity Regulation) enables anything from a cost-based model to a market-based model, depending on the framework and conditions within each member state. The ElWOG in Austria only enables the implementation of a cost-based model. Therefore, any implementation of a remuneration model beyond a cost based one is subject to discussion. In this context the desirability of a cost model for redispatch in Austria beyond cost based must be discussed.

This section elaborates on the industries perspective which has been discussed within the setting of a world café within the projects consortium, the advantages and disadvantages of the possible cost models as well as the risk of gaming. Furthermore, it discusses if the circumstances in Austria would allow a market based redispatch model and whether redispatch potential is sufficient for such a form of remuneration. Finally, the necessity to adapt the regulatory framework regarding the financial compensation is discussed. However, this analysis cannot make an estimation whether a market model is the economically most efficient model. An economic analysis would have to be done based on a cost benefit analysis. This deliverable can only discuss the attractiveness of cost models for industry and make an estimation whether a market-based model would be technically feasible, I.e., the redispatch potential is sufficient to enable a competitive market.

### 10.3.1. The industry's perspective

A strictly cost based model does not provide any incentive to industry to provide redispatch. The most obvious reason is that the participation in any non-mandatory actions or service provision is only interesting if it yields profits. Besides this self-evident statement the discussion with the projects industrial partners in the form of a “world café” has resulted in a list of issues that should be addressed when designing a remuneration model.

Besides the marginal costs associated with a single redispatch bid, there are additional costs associated with the participation on a redispatch platform that cannot be directly attributed to individual redispatch bids/requests. First, there is the investment in the infrastructure necessary to exchange data for the operational process as well as hardware and software for automation. Then there are the costs associated with the daily planning, schedule announcement and placing of redispatch bids independent of whether the latter are selected. These costs need to be covered somehow. Especially the CAPEX component needs to be covered within a reasonable timeframe (approx. 3-5 years). This requires that such fixed costs are either reimbursed separately or as an additional markup for every redispatch bid. This markup on redispatch bids in turn requires that the FSP can make reliable estimations of the provided redispatch volume in a single year, so that the sum of all markups is higher than the fixed costs resulting from operations and annualized investment costs that are not directly connected to an individual bid.

The resulting revenue opportunities of the FSP in general compete with the grid operators’ efforts to develop their grids and thus reduce the frequency of congestions and of congestion management costs. While grid expansion projects usually take several years from planning to execution, they are then in service for decades in order to recover their costs. Long-term investments to participate in redispatch provision must be evaluated based on their economic feasibility and becomes difficult if the time to recover the costs is limited by the implementation of grid expansion projects by the TSO/DSO. The planned grid expansion projects in the Austrian transmission grid are defined in the

Ten Year Network Development Plan (TYNDP) (see also [58]) and the Austrian grid development plan (ger.: “Netzentwicklungsplan” [59]).

Apart from the financial aspects, any model with a cost-based component comes with the requirement to provide detailed data of the cost components to the TSO and to the regulator. This apparently comes with a significant organizational effort for the redispatch service provider. To address these challenges, the industry partners of the project propose either a small reward for the participation on the redispatch platform/in the process to cover (at least) the expenses for schedule announcement and the placement of bids or a market-based model. While the implementation of a market-based model would have to be evaluated on a national level considering the socioeconomic costs associated with the implementation, the general need to address the costs not directly linked to an activated bid must be addressed in order to make redispatch attractive for industry and aggregators.

Furthermore, there is the aspect of opportunities: In general, there is the competition between the markets (spot markets, balancing and redispatch) which compete for the asset's flexibility. If the remuneration of redispatch is too low the service provider might opt to participate in another market. This issue is independent of the market model deployed. Furthermore, it is necessary to specify which opportunities are compensated within a remuneration model with a cost-based component. An overview of the cost components is given in Deliverable 3.3 Annex D.

Finally, the optimisation of industrial processes to identify flexibilities is most effective if the timing and direction of redispatch demand is known as early as possible. Suggestions were made ranging from hours to several days, which could enable more industrial flexibility potential. Better ex-ante information on redispatch demand allows their algorithms to optimise processes in order to create flexibilities in the hours redispatch demand is most likely to occur. Such ex-ante information on the timing of redispatch demand is both in conflict with the interests of the TSO/DSO as it is likely to increase the risk of gaming and limited by current market timings. Furthermore, the timing of international redispatch processes (grid security analysis starts 18:00 day-ahead, after GCT of the redispatch-platform) doesn’t facilitate such early announcements, because the information is not yet available at the time of GOT of the redispatch platform.

To summarise the requirements for the remuneration from an industry perspective the remuneration for participating in redispatch should allow for profits of the FSP. The remuneration model should allow the FSP to recover costs not directly related to the activation of a single bid and the expected earnings for participating in redispatching should be competitive when compared to other markets such as balancing and intraday trading.

#### 10.3.2. Advantages and disadvantages of different cost models

In classical economic theory goods and services are either exchanged in an open market or ordered and compensated by an authority on a cost or tariff-based scheme. In the theory of a perfect competitive market the market-based exchange of goods and services requires a set of preconditions that facilitate a fair exchange. Among others, these include:

- A large number of buyers and sellers
- A homogenous product
- Low barriers to entry

In cases where these prerequisites cannot be fulfilled regulatory approaches are oftentimes used to enforce cost-based or rate based procurement of such services combined with an obligation to contract. Thus, in general the provision of redispatch may be compensated in a fully market-based model or via a more regulated cost-based model, with reimbursement of the incurred costs based on mandatory participation. Another possible compensation model is a regulated rate of return model, in this text often referred to as cost+ model, where the compensation is based on the incurred costs but redispatch providers are guaranteed a markup as an incentive to offer their services. Whether the procurement of redispatch can be market based remains up for debate. Redispatch is by its nature highly segmented due to the different characteristics of generators and loads, and the location dependence of congestions. There might also be a high barrier of entry for new providers as assets need to be equipped or retrofitted with IT and control systems. As a result redispatch is currently provided by a low number of sellers and a single buyer. At last the demand for redispatch is volatile and very inelastic and the buyer of redispatch has a no rational short term option to substitute redispatch. This has caused the member states of the European Union to take different paths when procuring redispatch as elaborated in chapter 9.

Each cost model comes with its own advantages and disadvantages from the perspective of the TSO, the national regulatory authority (NRA)/Austria and the FSP. This chapter discusses the different pros and cons of a cost-based, market-based, cost+ model. An overview is given in Table 6. The pros and cons of an additional capacity price are discussed at the end of this section.

| COST MODEL | COST BASED | COST+ | MARKET-BASED |
|---|---|---|---|
| **PRO** | + lower costs<br>+ higher efficiency if there are only few participants | + slightly higher incentive to participate<br>+ Higher remuneration could cover additional costs of industry | + higher incentive to participate<br>+ Higher remuneration potential could cover CAPEX/addition costs |
| **CON** | - Low incentive to participate<br>- Mechanisms to secure capacity required<br>- Effort for supplier to justify costs<br>- Effort for TSO/NRA to verify costs<br>- Information asymmetries between TSO/NRA and RD supplier<br>- Solution to cover CAPEX needed | – Tendency to increase socio-economic costs<br>– Effort for supplier to justify costs<br>– Effort for TSO/NRA to verify costs<br>– Information asymmetries between TSO/NRA and RD supplier<br>– Solution to cover CAPEX needed | – Tendency for (inc-dec) gaming<br>– Tendency to increase socio-economic costs<br>– Validation by TSO/NRA of RD cost probably still necessary<br>– FSP bidding strategy to cover CAPEX needed |

***Table 6: Advantages and disadvantages of possible remuneration models***

### Cost-based model

The cost-based model only remunerates the actual costs directly associated with the redispatch delivery.

Beneficial for the TSO and the NRA is the relatively high predictability of costs since the participants and their cost components are known as well as the lower costs, since the redispatch delivery is obligatory and only based on the costs. Disadvantageous is the low incentive for industry to participate since they are not obliged. Furthermore, mechanisms are required (grid reserve) to ensure sufficient potential is available.

Another disadvantage is the effort for the RD supplier to justify its costs in detail. This also is connected to the effort for the TSO and the NRA to verify the costs. In general, there is an asymmetry of knowledge between the FSP and the TSO/NRA: Even if the detailed costs are laid out by the FSP, it has more information about the occurred costs and might list costs that never actually occurred, which can only be veri-/falsified by the NRA/TSO to a certain extent. Thus, even a cost-based model, might not be fully cost based.

Finally, a solution has to be found to cover the FSPs costs not directly connected to the provision of a single redispatch bid, i.e. CAPEX as well as the OPEX caused by schedule announcement and the placement of bids. One might argue that investments made to facilitate the participation in the RD platform (IT infrastructure, etc.) are also costs to be covered within a cost-based model. This, however, is subject to discussion with the regulatory authority.

### Cost+

A cost+ model remunerates the costs directly connected to a redispatch measure plus a markup. Such a markup might be defined as an absolute value (e.g. 5 €/MWh) or dynamic, based on the prices on competing markets. It may also be combined with or reduced to the compensation of investment costs. Whether this model would be applicable to all flexibility service providers or just a subgroup (e.g. only industrial FSPs, loads or FSPs with a certain size) is open to discussion.

Such a model provides a higher incentive for industry to participate. The additional remuneration might cover costs not directly linked to the activation of a RD measure (schedule announcement and placement of redispatch bids), depending on the frequency of activation. On the other hand, it increases the socio-economic costs for Austria.

Since one component is cost based and the other is defined by the regulator costs are also fairly predictable.

Some of the disadvantages from the cost-based model remain in a cost+ model: the effort for the RD supplier to justify its costs in detail, which is also connected to the effort for the TSO and the NRA to verify the costs. The asymmetry of knowledge between the FSP and the TSO/NRA must be mentioned here: Even if the detailed costs are laid out by the FSP, it has more information about the occurred costs and might list costs that never actually occurred, which can only be veri-/falsified by the NRA/TSO to a certain extent. Thus, a markup is applied twice: once when the FSP displays its costs indirectly and second when the actual Markup is applied.

Similarly, to the cost-based model one could argue that investments made to facilitate the participation in the RD platform (IT infrastructure ect.) are also costs to be covered within a cost-based part of a cost+ model. This would be subject to discussion with the regulatory authority.

**Market-based model:**

A market-based model remunerates service providers based on bids placed by market participants(pay-as-bid). Bids may be placed freely. Such a cost-model probably provides the highest incentive for industry to participate. Since the FSP can define its own “markup”, the potential earnings seam the highest and a quicker recovery of the CAPEX as well as the costs not directly connected to the activation of bids appear possible, if the FSP’s bids are activated frequently enough. In this case the FSP bears the risk of whether the CAPEX can be covered within a reasonable time.

However, it also bears the highest risk to increase overall prices and the socio-economic costs. Especially when one considers the potential impact of increase-decrease gaming which is discussed further in chapter 10.3.3.

When a market-based model is deployed, the TSOs and NRAs responsibility to validate the costs might still be given, since the effectiveness of the market needs to be observed, to ensure prices are reasonable and measures can be taken to counteract gaming tendencies or the potential market power of bidders.

**Mixed models:**

Instead of the implementation of a single remuneration model this section discusses the implementation of more than one model which is hereinafter referred to as mixed models. The aim is to address the individual disadvantages of the models by implementing different mechanisms for the same service.

In order to manage the limited liquidity in the redispatch market the preservation of the grid reserve (GER: “Netzreserve”) or a similar mechanism for the provision of redispatch potentials is required and therefore an essential component of any of the mixed models discussed. The grid reserve is procured market-based, however the individual activations are then remunerated cost-based.

The following mixed models are conceivable:

1. Combining market-based redispatch and cost based redispatch from grid reserve (**market & grid reserve**)
2. Combining market-based demand response (redispatch by withdrawing parties) and cost-based redispatch by conventional power plants and plants under the grid reserve regime **(generation-DSR segmentation**)
3. Combining market-based redispatch by plants below a certain asset size with cost-based redispatch by conventional power plants and plants under the grid reserve mechanism (**capacity based**)

The implementation of mixed models requires the definition of a clear separation between the different mechanisms, i.e. their mode of segmentation and the management of their interdependencies, i.e. their order of application. If multiple mechanisms are deployed for the same service, the bids of the different services can either be applied sequentially or combined in a common merit order. In case of sequential deployment one mechanism is primarily used to meet the demand and the second is only used as a backup, if the supply in the initial market is insufficient to cover the entirety of the demand. The option to activate the market-based product last is disregarded, because in such a configuration the flexibility providers in the market-based mechanism know that they are the last resort which might result both in few activations and in high prices. Activating bids in the market first might also result in high prices, if the liquidity is low. The other option would be a parallel application of market-based and cost-based providers in a common merit order. In such a configuration the bids of all mechanisms are combined in a common merit order and only the most economically efficient are activated. Such a configuration may lead to low activation of market based redispatch if the price of industrial flexibility cannot compete with cost-based provision and market-based offers are squeezed out of the merit-order by conventional cost-based units.

An overview of the advantages and disadvantages of the different mixed models and their deployment methods is given in Table 7.

| MODE OF MARKET SEGMENTATION | ORDER OF DEPLOYMENT | PRO | CONTRA |
|---|---|---|---|
| **MARKET & GRID RESERVE** | Sequential | + high incentive for new participants (e.g. industry) to join the market | - Liquidity issue remains<br>- High redispatch costs<br>- “expensive grid reserve”; procurement of power that is rarely used<br>- Management of the dynamic between the different mechanisms (definition which share of demand is to be met by which market)<br>- Consideration of different mechanisms in international processes (ROSC) |
| | Common merit order | + moderate redispatch costs due to the consideration of cost-based power plants in the merit order | - Low frequency of activation of participants (e.g., industry)<br>- Management of the dynamic between the different mechanisms (plants might leave grid reserve to offer on the market) |
| **GENERATION-DSR DIFFERENTIATION** | Sequential | + high incentive for new participants (e.g. industry) to join the market | - Liquidity issue remains<br>- High redispatch costs<br>- Management of the dynamic between the different mechanisms (definition which share of demand is to be met by which market)<br>- Consideration of different mechanisms in international processes (ROSC) |
| | Common merit order | + moderate redispatch costs due to the consideration of cost-based power plants in the merit order | - Low frequency of activation of participants (e.g., industry)<br>- Management of the dynamic between the different mechanisms |
| **CAPACITY BASED DIFFERENTIATION** | Sequential | + high incentive for new participants (e.g. industry) to join the market | - Liquidity issue remains<br>- High redispatch costs<br>- Management of the dynamic between the different mechanisms (definition which share of demand is to be met by which market)<br>- Consideration of different mechanisms in international processes (ROSC) |
| | Common merit order | + moderate redispatch costs due to the consideration of cost-based power plants in the merit order | - Low frequency of activation of participants (e.g., industry)<br>- Management of the dynamic between the different mechanisms |

***Table 7: pros and cons of mixed models***

**Capacity Price**

In addition to the cost-model for the activation of redispatch measures, a TSO or a member state may also introduce an additional capacity market in order to ensure the availability of sufficient redispatch capacity. The introduction of a capacity price could solve the issue of costs not directly linked to redispatch measures (CAPEX and costs caused by scheduling and RD bid placement) and could provide a high incentive to industry to participate. However, a capacity price could potentially also increase the socio-economic costs and introduce new challenges that must be considered, which range from the required notification at EU level, determining the capacity to be contracted as well as the capacity market design.

Furthermore, without an obligation to bid, the incentive for industry to place bids, i.e. actually provide their flexibility would be rather low. Furthermore, if the simultaneous participation on different markets (spot market, balancing and redispatch) is allowed in combination with a capacity price, this might increase the risk of gaming and the socio-economic costs even further.

Currently there is already a market-based procurement of redispatch capacity in place: the grid reserve. The Austrian grid reserve is not a capacity market in the classical sense but only a secured capacity for redispatching. Any eligible providers of redispatch, including industrial providers of redispatch, can participate in the tendering process if they meet the requirements. Currently redispatch demand in Austria can be met by units available in the market and the units additionally secured by the grid reserve. The grid reserve already procures the capacity required for the whole year. Whether another additional capacity market is sensible is questionable.

| COST MODEL | CAPACITY PRICE |
|---|---|
| **PRO** | + higher incentive to participate<br>+ Higher remuneration potential could cover CAPEX/addition costs |
| **CON** | – Incentive to place bids is lower<br>– Tendency to increase socio-economic costs<br>– Simultaneous feasibility with existing grid reserve not given<br>– Simultaneous participation on other markets (if possible) could increase gaming and socio-economic costs |

### 10.3.3. Increase-decrease gaming

In the context of establishing remuneration methods for redispatch, the risk of gaming strategies plays an important role. Market participants may take advantage of the way redispatch gets procured after the majority of energy was traded on the day-ahead market. Therefore, the following chapter discusses which strategies could potentially be implemented by market participants, which conditions must be met for participating in such strategies and which appropriate mitigation and countermeasures are suggested by literature and applied in other countries.

#### 10.3.3.1. Definition and requirements

When looking at two sequential markets, on which practically the same products can be offered, there is always a risk of potential arbitrage trading. In the case of a redispatch market, which starts after the day-ahead market, it seems rational to take advantage of opportunities between those two markets. This might lead to strategical bidding behavior of market participants in order to raise their profits. Such behavior can result in an inefficient market outcome and welfare losses [51], [60].

The most popular strategy in this context is the Inc-dec gaming, as described by [53] based on game theoretical analysis. This includes the strategic behavior for two different types of providers, those that are in regions where regulation is predominantly downward and those which are predominantly regulated upward. Both cases are described as follows:

***Downward region strategy:*** *This concerns redispatch providers who expect to be regulated downward. These market participants may be tempted to* ***decrease the price of their offers*** *in the day-ahead market while* ***increasing the quantity offered*** *to increase the infeed within their proximity and increase the risk of congestion. Because of the expectation to be regulated downward anyway, this results in profits for quantities they never would have planned to produce in the first place.*

Besides the profits due to the inflated sales on the day-ahead market, they could make even more profits depending on the redispatch remuneration approach. In a market-based approach, with few other providers of redispatch the player may then offer a low, or even a negative price for downwards regulation (i.e., the FSP receives money from the TSO whereas the TSO must provide the upwards regulation to compensate the missing energy). Even according to a cost-based remuneration mechanism this strategy could be beneficial for providers as long as the profit from selling on the day ahead market outweighs the costs for downward regulation). This gaming strategy can increase profits by adjusting the prices offered, but also by adjustments of the offered volumes.

***Upward region strategy:*** *This applies to providers who expect to be regulated upward. It is beneficial for those suppliers to* ***decrease or withhold their offered quantities*** *on the day-ahead market while* ***increasing their offered prices*** *up to the level they expect to achieve for redispatch. This comes together with the expectation of achieving higher prices for redispatch than for selling on the day-ahead market. Consequently, they artificially increase demand for upward regulation in order to sell their available volumes at these prices.*

This strategy (I.e., upward region strategy) depends on a remuneration mechanism for redispatch that promises higher margins compared to day-ahead prices.

Although in theory the benefits of gaming are obvious, there are some factors and uncertainties that make successful gaming difficult to predict. Generally, the incentives to participate in gaming behavior depend on two crucial factors:

1. The potential profit if the strategy is successful and
2. the probability that it actually is successful.

The achievable margins depend on the price differences between the two markets. These margins must be compared to the losses that will be made if the gaming is not successful. Uncertainties can arise due to a variety of reasons e.g., the probability of congestion to occur in the first place, the impact of competition in the form of demand side flexibilities[18], as well as the behavior of other market participants. There are two main circumstances which enable gaming behavior:

1. If congestion is structural, i.e., frequent and predictable, or/and
2. due to the presence of market power of individual market participants.

In the case of market power, redispatch providers with a dominant position due to their location or market share can enforce prices above their marginal or opportunity costs [39], [51]. In general, it should be noted that monopolistic market scenarios are generally considered imperfect and therefore require additional accompanying measures.

In terms of structural congestions, the level of liquidity plays an important role. The authors of [46], [61, p. 51], [62, p. 4] noted, that due to a variety of different uncertainties the appearance of strategic gaming behavior is very unlikely within highly competitive markets. With sufficient level of competition, the potential profit and the probability of success decrease, and gaming becomes less attractive.

[18] In [53], the analyzed model doesn't consider the role of integrated demand response.

#### 10.3.3.2. Mitigation and countermeasures

As described above, the consideration of strategic behavior is crucial when establishing a remuneration method for redispatch. To increase the risk for flexibility providers to benefit from engaging in gaming strategies, it is significant to develop a market design (regardless of whether the remuneration is cost- or market-based) which is easily accessible and economically attractive for market participants. In other words, the market design should attract many participants and thus increase liquidity. In this regard many countries in Europe which implemented a redispatch market linked their procurement to another prevailing flexibility market and integrated demand response to further increase the availability of assets (see also chapter 9.2).

However, the geographic nature of redispatch demand might still lead to limited availability of suitable redispatch potential. Increasing the liquidity in a market is crucial but doesn't provide a solution to avoid gaming completely. In regions where liquidity is still low, or market power is present, additional accompanying measures should be considered. Such measures can be grouped into *ex-ante* and *ex-post* countermeasures. All measures observed in other countries that employ market based redispatching are summarized in Table 8, which further includes examples of countries in which the respective measures are implemented.

| | Measures | Implemented in |
|---|---|---|
| Liquidity | Demand response | BE, FR, GE, GR, NL, NO, ES |
| | Linked to another flexibility market | BE, FR, GR, GB, IT NL, PL, ES, CH |
| Ex-Ante | Long-term Contracts | GB, PO, SE |
| | Surveillance and control by law | GB, NL, NO; EU (i.e., REMIT) |
| | Splitting bidding zones | IT, NL, NO, SE |
| Ex-Post | Independent market monitoring | NL |
| | Baseline & compliance methodology | - |
| | Reference level prices | GB, NL |

***Table 8: Mitigation measures deployed in EU countries***

***Ex-ante*** measures include inter alia the expansion and enforcement of existing legislation. For EU-members, such regulation is partly implemented in the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) [63]. There it is stated that Inc-dec bidding is a violation of competition law or sector-specific regulation. The Netherlands, for example, additionally implemented a regulation that requires a minimum of three competing market participants (including demand response and storage) to enable market-based redispatch procurement [55], see chapter 9.2.2.

The negotiation of long-term contracts could be used as a supportive measure within regions where competition is expected to be low. Those contracts can be designed in many different ways. They can include agreements on the extent to which bids have to be submitted over a certain period of time, determine fixed prices for withholding capacities, or simply a fixed energy price that is only paid in the event of activation. Depending on the arrangement, other providers would still be in competition to capacities already agreed upon. Such contracts are also effective in order to regulate market power.

Another *ex-ante* measure is the modification of bidding zones. The idea is to split bidding zones in case of structural congestion and thereby reduce the demand for redispatch in advance. Structural and physical congestion should be reflected more appropriately by the new bidding zones. However, dividing bidding zones is not reasonable for every country.

***Ex-post*** measures describe the monitoring and review of market transactions. National regulatory authorities may introduce mechanisms to identify cases of Inc-dec gaming or the exercise of market power. The provision of a proper baseline and definition of certain data exchange (I.e., that enables to evaluate whether participants significantly deviate from their true costs) can prevent demand response providers or aggregators from offering volumes they couldn't deliver [55]. However, consumers who supply flexibilities are in general more risk averse when it comes to gaming strategies. Their costs of an unsuccessful gaming attempt are much higher in comparison to conventional generators. Also, their expected profits would be significantly lower compared to their actual production process. Another approach taken by Norway and Great Britain, is the comparison of bids to reference level prices [46], [54]. The establishment of reference level scenarios could help to either detect suspicious low bids within the day-ahead market as well as significantly higher bids for redispatch. In the case of Norway, they check if the marginal prices for the respective technology are on average higher than 19.5% than usual for that time period in the day-ahead market [46], see also chapter 9.2.2. Such reference prices can also be interpreted as (technological specific) dynamic price caps. Generally, *ex-post* monitoring measures should always be linked to penalties to prevent strategic behavior in advance.

Table 8 shows that many countries are primarily trying to increase liquidity, which not only decreases the risk of behaving strategically, but generally enables the decrease of market prices and should therefore be considered. Beside applying the suggested measures to avoid inc-dec gaming, the use of *ex-ante* measures is traditionally established for regulation of the power grid and for ensuring sufficient capacity. Nevertheless, such measures are strongly dependent on the characteristics of the respective country and should therefore be carefully evaluated before being implemented. In comparison, *ex-post* measures are rather uncommon in the context of mitigating gaming behavior. This is probably because market-based redispatch procurement is still new in some countries and the implementation of additional measures might be considered in the future. However, the monitoring of market behavior is not unusual and therefore would be an option for redispatch markets as well. In general, the measures listed above are based on literature research and individual countries. More detailed evaluations and the possible development of further alternatives have to be considered.

### 10.3.4. Analysis of market-based redispatch in Austria

In order to evaluate the feasibility of a market-based redispatch the liquidity in such a potential market was analysed. This chapter describes the aim of the analysis, the data input and assumptions made to conduct the analysis, the results and finally makes conclusions on the meaning for the implementation of remuneration models.

#### 10.3.4.1. Aim of the analysis

Considering the risks of gaming within marked-based models, it is important to understand the circumstances under which such a model might be deployed in Austria. To gain a better understanding of the liquidity in such a market, the redispatch potentials that might be offered within such a market were analysed and compared with the historic redispatch demand.

The main research questions of this analysis can be summarised as follows:

- What are the minimum and maximum redispatch potentials available in Austria?
- What is the range of redispatch demand in Austria.
- Considering these circumstances, is a market-based redispatch technically possible?

The analysis was conducted to gain a general insight in the liquidity on a redispatch market. The detailed modelling of efficiencies on specific congestions was neglected, hence the results may only be interpreted as a rough estimation. In conclusion the analysis of redispatch potentials and comparison with the historical redispatch demand shows that a majority of redispatch potential is controlled by a few market participants which might therefore have significant market power and that the freely available redispatch resources without grid reserve are of a similar magnitude as the historically requested redispatch and may thus be insufficient for a fully market-based redispatch. At last, the necessity of the existing grid reserve mechanism is also an indication that the legal obligation to participate in redispatch was not enough to secure sufficient redispatch potentials, but an additional instrument was needed. These limitations have to be considered when configuring options for the integration of industrial plants into redispatch processes.

### 10.3.5. Possible remuneration models to enable Industry4Redispatch

The evaluation of remuneration models in the context of Industry4Redispatch has to take into account the industries perspective laid out in chapter 10.3.1 as well as the system operators' objective. This requires a balanced approach between providing the industries with a reasonable financial incentive for the provision of redispatch and system operators' priority to facilitate secure network operation at all times at reasonable costs. Costs resulting from network operation are borne by all grid users. If the costs of system operation increase due to redispatch, system charges increase accordingly. Thus, it is in the interest of system operators (and all grid users in Austria) to minimise redispatch costs.

The system operators aim at enabling the integration of ever increasing amounts of renewable energy, which poses additional challenges to system operation. To be able to handle these challenges, system operators need to make sure there is sufficient flexibility potential available. Due to the ongoing changes in the electricity sector, exacerbated by the gas crisis of 2022, the availability of gas and coal dependent thermal plants is drawn into question.

Hence, it is important to increase the amount of available redispatch potential and diversify the types of flexibility potential. The E-Control study carried out by the "AIT Austrian Institute of Technology GmbH", "Technische Universität Wien" and the "Forschungsstelle für Energiewirtschaft FfE" has analysed technical and actual potentials for the years 2020 and 2030 [64]: It demonstrates the decrease in flexibility potential of conventional producers due to the reduction of fossil fuels and the potential increase of flexibility potentials of other sources such as industry, power to gas, storages and demand side management.

The previous sections of this document have shown that following remuneration models could be considered for redispatch:

- Cost-based redispatch, whereby providers are strictly remunerated for their costs and economic disadvantages
- Cost+, where providers are incentives either through fixed markups or through premiums for participation
- Mixed models, where a form of market-based procurement is complemented by an additional cost-based mechanism
- Market-based redispatch

The advantages and disadvantages of cost-based, cost+ and market-based model are listed in chapter 10.3.2.

While the currently deployed cost-based model appears to be the most cost-effective model to the system operator and the Austrian grid users, the participation of industry is unlikely as it lacks an economic incentive for owners of industrial facilities to participate. As the flexibility potential of industrial processes cannot be assessed from the outside, i.e. the TSO, participation requires voluntary commitment by the industrial facilities and participation obligations are unlikely to yield the desired results.

Based on the analysis in chapter 10.3.4 purely market-based redispatch has to be excluded from the viable options as well, since liquidity appears to be insufficient at the present composition of redispatch demand and flexibility potential in Austria, and the presence of market power could enable gaming behaviour. Thus, in the perspective of the project consortium, only a cost+ or some form of mixed models remain as a potential future remuneration scheme for redispatch, which could enable industry participation.

#### 10.3.5.1. Cost + vs. mixed models

Since purely market-based redispatch is currently not possible in Austria, the only options to address the industries' needs and thereby enable their participation are the cost+ model and mixed models.

The total redispatch costs are more predictable in a cost+ model, whereas mixed models are far more complex to implement and to manage. The cost-based component of the cost+ model ensures that redispatch costs reflect the actual costs of the FSP. However, in a mixed model prices would be defined market-based for industrial FSPs (and other FSPs within the market-based mechanism). As described in the previous chapter the advantage of sequentially deployed mixed models is their incentive for new FSPs to participate, however, additional measures are required to manage prices.

The introduction of price caps to the market-based segment of a mixed model provides circumstances for the FSP not dissimilar to a cost+ model: the price cap defines the maximum sum of the FSPs costs and profits, that can be achieved with market-based bids (equivalent to costs + markup). The definition of a price cap within a market-based mechanism or segment can thus be interpreted as the indirect definition of a maximum markup, but it is uniformly applicable to all bidders and thus the actual “markup” in case of varying marginal costs may be different especially when most FSPs bid close to the price cap in case of low liquidity in the market. In contrast to the cost+ model the detailed costs don’t have to be laid out by the FSP in a market-based model with a price cap, which could reduce the organisational effort of the FSP.

The implementation of mixed models in a common merit order with a large share of cost-based bids would regulate prices on its own, provided, that liquidity is sufficient. In this case new participants would only be activated if they are able to compete with the cost-based assets. Here additional incentives would be required to reduce initial hurdles of participation (e.g.: Installation of IT interfaces and setup of processes).

There is no optimal model to enable the integration of industrial FSPs in the redispatch process: Each of them comes with the challenge to balance the industry’s needs and the socioeconomic costs for Austria.

## 11.Summary

In recent years redispatch has become an important tool for TSOs across Europe to solve congestions and multiple regulations were passed in order to build a legal framework for system operators and providers of redispatch alike. In this regulatory analysis of redispatch procurement national laws as well as EU regulations were observed.

Under Austrian Law, the legal acts governing redispatch are the national ElWOG and the respective NEP-VO. On European level, redispatch is governed by the EU Regulations and Directives of the third and fourth Package, Regulation (EU) 2017/1485 ("SO GL"), Regulation (EU) 2019/943 ("Electricity Regulation"), Directive (EU) 2019/944 ("Electricity Directive") and Regulation (EU) 2015/1222 ("CACM"). The CACM also requires the development of a common methodology for redispatching, countertrading and cost sharing, which is also binding for TSOs and which has been realized by the TSOs in the form of the ROSC Methodology for the CCR Core and the ROSC Methodology form CCR Italy North. Furthermore, a Framework Guideline on Demand Response is currently in the consultation phase), which might introduce further requirements regarding the participation of demand facilities and aggregators as well as the configuration of redispatch requirements and processes. Furthermore, on European Level the NC DCC and NC RfG as well as the national TOR, SOGL Dataexchange-R and SoMa provide relevant regulations on grid connection and responsibilities for data exchange.

The regulatory analysis was compared with the redispatch requirements developed in the projects Deliverable 3.3 to identify **regulatory gaps** which would require adaptation. While the definition of TSO redispatch. The TSOs and the technical units' roles and responsibilities regarding redispatch as well as the grid connection requirements are regulated sufficiently, the following subjects require adaptation:

- The roles and responsibilities regarding redispatch, attributed to the DSO are not defined within the national ElWOG and while some federal ElWOGs allow for DSO redispatch the legislation is not harmonised within Austria
- While the SGU definition in the SO GL would be in line with the participation of industrial FSPs and virtual power plants, the definition in the SOGL Dataexchange-R comes with more limitations. In general, all potential redispatch providers are significant grid users independent of their size. This should be reflected in the national definition of SGUs.
- There is currently no obligation to exchange schedules for demand facilities, that are SGUs connected at the distribution level
- Financial compensation of redispatch is limited to economic disadvantages and incurred costs by the national ElWOG

The aim of the project Industry4Redispatch is to relieve network congestions on different grid levels. Future TSO-DSO cooperation shall utilise common flexibility potentials for Redispatch to relieve congestions at all relevant grid levels. Since most of the current federal regulations do not enable **DSO Redispatch**, it is suggested to extend the national definition of congestion management to applications at distribution grid level and to harmonise the congestion management obligations and responsibilities by the DSO across the federal ElWOGs.

Since the **definition of SGU** is relevant for the grid users responsibilities regarding data exchanges relevant for the system operators grid security analysis it plays an important role in enabling the participation of industrial facilities in redispatch. Since the national "SOGL Dataexchange-R" currently restricts the SGU definition by Art. 2. (1)(d) SOGL to significant demand facilities providing demand response directly to the TSO in accordance Art. 27 RfG with an installed capacity ≥ 25 MW, an adaptation of the definition in the SOGL Dataexchange-R would be required, in order to address redispatch providing demand facilities with an installed capacity below 25 MW.

**Schedules** are the basis of the system operators grid security analysis and function as a baseline for redispatch provision. The current SOGL Dataexchange-R doesn't require demand facilities to provide schedules. Here the requirement to transmit schedules to the TSO would have to be added to the obligations of demand facilities with a similar wording to that of transmission connected demand facilities. Such a requirement could either be added to the requirements for participation in redispatch by the TSO while it is not yet regulated by other texts or it could be included within the SOGL Dataexchange-R or the SoMa. At the time of writing a new version of "SoMa Schedules"

(GER: Sonstige Marktregeln Fahrpläne) is under consultation. If the definition of schedules described in the SoMa would be adapted to cover schedules of demand facilities, especially those providing system services such as redispatch, the participation of demand facilities in day-ahead redispatch would be enabled.

The Regulation (EU) 2019/943 (Electricity Regulation) enables any **remuneration model** from a cost-based model to a market-based model, depending on the framework and conditions within each member state. The ElWOG in Austria only enables the implementation of a cost-based model. Therefore, any implementation of a remuneration model beyond a cost based one is subject to discussion.

In this deliverable the industries perspective, the advantages and disadvantages of the possible cost models as well as the implementations in different European countries as well as the risk of gaming were discussed. Furthermore, it was analysed if the circumstances in Austria would technically allow a market based redispatch model and whether redispatch potential is sufficient for such a form of remuneration.

The requirements from an industry perspective are that the remuneration for participating in redispatch should allow for profits of the FSP. The remuneration model should allow the FSP to recover costs not directly related to the activation of a single bid (such as investments in atomisation infrastructure) and the expected earnings for participating in redispatching should be competitive when compared to other markets such as balancing and intraday trading.

System operators at the other hand must aim at keeping the costs resulting from network operation to a minimum. These costs are borne by all grid users; if the costs of system operation increase due to redispatch, system charges increase accordingly. Thus, it is in the interest of system operators (and all grid users in Austria) to minimise redispatch costs.

The European countries have implemented different remunerations models in accordance with the circumstances in the respective circumstances. There is a tendency for countries with low redispatch demand to employ market-based models while those with high redispatch demand implement either cost-based models or a mixture of mechanisms. Where market-based remuneration is implemented, it is usually accompanied by measures to mitigate gaming behaviour. The choice of such countermeasures is strongly dependent on the country specific circumstances. No European country is implementing a cost + markup model.

A basic analysis of the historic redispatch potentials and demand has shown that the liquidity would currently not be sufficient to enable a purely market-based remuneration of redispatch in Austria.

**Since purely market-based redispatch is currently not possible in Austria the only options to address the industries needs and thereby enable their participation are the cost+ model and mixed models. There is no optimal model to enable the integration of industrial flexibility service providers in the redispatch process: Each of them comes with the challenge to balance the industry's needs and the socioeconomic costs for Austria.**

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# Annex A

### Requirements for grid connection of generators

The NC RfG describes requirements for new power generation plants for connection to electricity grids. These requirements increase with the size of the generation plants. As defined by Art. 5 NC RfG the requirements to be met by power generation modules are dependent on the following categories, based on the voltage level of their grid connection point and their maximum capacity.

a. Typ A:

   maximum capacity ≥ 0,8 kW

   connection point below 110 kV

   general requirements: Fundamental requirements for frequency stability to avoid large-scale critical network conditions; limited automatic regulations

b. Typ B:

   Maximum capacity ≥ 250 kW

   connection point below 110 kV

   general requirements: automatic control systems, robustness, remote control technology

c. Typ C:

   Maximum capacity ≥ 35 MW

   connection point below 110 kV

   general requirements: voltage maintenance (reactive power), extended frequency maintenance, system management & system recovery

d. Typ D:

   Maximum capacity ≥ 50 MW or connection point ≥110 kV

   general requirements: extensive operational management and stability requirements