Federatie van de elektriciteits- en gasnetbeheerders in België
Fédération des gestionnaires de réseaux électricité et gaz en Belgique

Report on the public consultation regarding the extension of the outage planning coordination process in the context of the phase 2 of iCAROS project

May 2026

1 Introduction

The aim of the joint DSO/TSO informal consultation on a design note on the coordination of outages of Technical Facilities (Outage Planning Coordination) in the context of iCAROS phase 2 was to receive feedback from stakeholders on this design. The consultation was launched on 16 July 2025 and ended on 10 October 2025. The consulted document can be found on the website of Synergrid and Elia.

This design note explains a harmonized process for the coordination of unavailability of technical installations. For transmission networks, this is an extension of the existing process. For distribution networks, this is a new obligation, which leads to a harmonized process regardless of whether the connection is to a transmission or distribution network.

This harmonized process applies to:

- Production and energy storage installations with a capacity of at least 1 MW, connected to the transmission grid, distribution grid or a close distribution system operator connected to the transmission grid
- demand sites directly connected to the transmission grid

Unavailability of these installations must be reported to the relevant System Operators (Elia and/or the DSO) in due time via an availability plan. This helps to ensure that grid operators can manage the grid more safely, detect and resolve congestion more quickly and schedule maintenance more efficiently, with as little disruption as possible to grid users.

Until now, the obligation only applied to larger installations (≥ 25 MW) connected to the transmission grid. However, the European Regulation on the operation of electricity transmission systems provides the possibility of extending the obligation to smaller generation and energy storage installations, regardless of whether they are connected to the transmission (or through a close distribution system operator connected to the transmission grid) or distribution grid, and demand sites directly connected to the transmission system.

As a result of this expansion, market parties are now involved for whom this type of information exchange is new. As such this design was first proposed through an informal consultation to these new stakeholders to give them the opportunity to suggest modifications to the design which would improve the quality of the received information and bringing it more in line with operational reality.

This design has been presented to stakeholders during a workshop that was organized by Synergrid on behalf of all System Operators on the 3rd of October 2025.

2 Feedback received

Synergrid has received individual feedback on the documents from 10 stakeholders of which 8 indicated that it was non-confidential information. More specifically the following stakeholders provided non-confidential information:

- 1.Aquiris
- 2.Bnewable
- 3.COGEN Vlaanderen
- 4.Edora
- 5.Febeg
- 6.Febeliec
- 7.Ventis SA
- 8.ODE

This consultation report reflects the received feedback from all stakeholders on the coordination of outages of Technical Facilities (Outage Planning Coordination) in the context of iCAROS phase 2.

3 Instructions for reading this document

This consultation report is structured as follows:

- Section 1 contains the introductory context;
- Section 2 gives the list of the parties who sent a response to the informal public consultation;
- Section 3 contains instructions for reading this document;
- Section 4 summarizes the various comments received during the informal public consultation and the System Operators' position on each of them;
- Section 5 contains the non-confidential feedback of market parties.

This consultation report is not a 'stand-alone' document and should be read together with the proposal submitted for consultation, the reactions received from the market participants (annexed to this document) and the updated design proposal.

Section 4 of the document is structured as follows with additional information on the content per column below.

Subject	Stakeholder	Feedback received	System Operators' view

A	B	C	D

A. Subject covered by the question(s)/feedback(s) received.
B. Stakeholder having provided the question/feedback.
C. Question/feedback received by the stakeholder.
D. System operators' answer to the question/feedback received, including the reasons why the System Operators have or have not taken the stakeholder's feedback into account in the final design.

4 Comments received during the informal public consultation

4.1 General comments

<table>
<tr><th>Subject</th><th>Stakeholder</th><th>Feedback received</th><th>System Operators’ view</th></tr>
<tr><td rowspan="2">General feedback</td><td>FEBEG</td><td>FEBEG thanks Synergrid and the Belgian System Operators for organizing this public consultation. The design note is clear, comprehensive and demonstrates a strong collaborative spirit between TSO and DSOs. This alignment is crucial: starting from the existing iCAROS framework and extending it step by step is the right approach. FEBEG particularly welcomes:
The intention to build on the current Outage Planning Agent (OPA) processes, ensuring alignment and consistency cross all regions and voltage levels with existing obligations for assets ≥25 MW.
The proposed single entry so that OPAs are able to use a single point of entry to communicate information for their entire portfolio, which will limit additional implementation costs for parties already connected. The proposed flexibility in communication channels (user interface or system-to-system interface) to ease the information exchange for the OPA’s.
We also refer to our earlier responses to Elia’s consultations on OPA which remain valid and should be taken into account.</td><td rowspan="2">The System Operators thank FEBEG and EDORA for confirming that both a common TSO/DSO design and the continued support of existing data exchange flows for large production and storage units connected to the TSO grid are valued by market parties. In line with these expectations, System Operators will provide market parties with a single interface - that maximally aligns with existing ones - for their entire portfolio and with additional (backup) channels for units that are important to operational security. The existing Elia interfaces will remain available for OPAs without DSO units and serve as backup in the event that the single point of entry is unavailable.</td></tr>
<tr><td>EDORA</td><td>EDORA thanks Synergrid and Elia for the organization of this consultation.</td></tr>
</table>

		EDORA welcomes the alignment of the new framework for outage planning with already existing practices for installations ≥ 25 MW and the aim to provide grid users with a common framework and a user-friendly interface to interact with System Operators.	

4.2 Implementation plan

Subject	Stakeholder	Feedback received	System Operators' view

Stepwise implementation	FEBEG	The next phases of iCAROS must be prioritized with the clear objective of cost efficiency in grid management and operational security.
		• Prioritization by size: Large demand facilities and large generating/storage units have the greatest relevance for system security, given their significant impact on available capacity and flexibility. By contrast, assets at the 1 MW threshold are much less critical and often owned or operated by parties with no experience in grid security processes.
		• Stepwise go-live: FEBEG strongly advocates for a phased implementation with successive waves, targeting the largest facilities first. For instance:
		  ○ Wave 1 (Q3 2027): demand facilities and generating/storage units ≥10 MW.
		  ○ Wave 2 (Q3 2028): assets ≥5 MW.
		  ○ Later waves (Q3 2029-…): smaller units down to 3 MW and after further evaluation down to smaller facilities.
			As mentioned in the design note, the option to implement this extension of outage planning coordination process in a stepwise approach was foreseen and left at the discretion of each System Operators (SOs). The evaluation would be done depending on the number of Technical Facilities requiring to be onboarded, the availability of the dedicated operational teams and the SO's specific constraint.
			Based on the feedback received and the expressed need for an aligned implementation between SOs not only in terms of design but as well in terms of size of the Technical Facility, the System Operators agreed on a two-waves onboarding process.
			The currently proposed design will be applicable to the entire scope, Technical Facilities smaller than 25 MW and greater or equal to 1 MW, and demand-sites directly connected to the Elia grid, with corresponding aligned contractual framework submitted for regulatory approval commonly by all System Operators to the competent regulators. Once approved, a two-wave onboarding process will be initiated, a first wave for Technical Facilities of size greater or equal to 5 MW and TSO-connected Demand Facilities, and a second wave for the extension of Technical Facilities down to 1 MW. After 6 months of normal operations a return of experience (REX) will be organized to assess whether a review of design is needed before starting the onboarding of the second wave. The different wave timelines will also be aligned between the System Operators.

		Such a phasing would allow intermediate evaluation and possible tweaking of the processes, which seems very useful due the very high number of smaller Technical Facilities to be integrated. For these smaller units, contractual discussions, implementation of IT tools, education, and adaptation of maintenance processes will require considerable time and resources. As many customers have assets in the different regions, FEBEG pleads for the same go-live date per wave in all the regions. This will ease the communication towards the asset owners.	The waved onboarding process, complemented with the return of experience, the dedicated training sessions and material put at disposal to the Outage Planning Agent (OPA), as well as a simplified outage planning coordination process, will contribute to a simplified and reduced effort implementation for less experienced OPA.
	FEBEG	FEBEG supports the alignment between TSO and DSOs and the effort to build on existing iCAROS processes, such coordination and alignment is essential to avoid even more complexity. At the same time, we stress the need for a pragmatic, realistic, and cost-efficient implementation path: • Go-lives should be organized in several waves, not a single step and include intermediate evaluations. • The largest units (especially demand facilities and large generating/storage units) should be targeted first, as they bring the most value for grid security. • The complexity and costs for smaller units (contractual, commercial, IT, operational) must be acknowledged, and their participation delayed until the framework is ready	
	EDORA	EDORA suggests phasing the implementation starting with biggest capacities first, gradually moving to lower capacities in subsequent phases. This phasing would enable small installations to start only when the system is ready. It will give sufficient time for small installations to organize the implementation processes that will require time and	

		resources. For many grid users, this new obligation to designate an OPA and forward the outage planning will require contractual and operational agreements to be made, in addition to technical implementation. Therefore, sufficient implementation time must be allowed for each phase.	
	ODE	We bevelen we een gefaseerde implementatie aan volgens geïnstalleerd vermogen om de outage planning door te geven. Er wordt best opgestart met de grootste vermogens. Bij deze beperktere groep zal het eenvoudiger zijn om goede begeleiding en opvolging te organiseren. Alvorens op te schalen naar de kleinere vermogens lijkt een uitgebreide evaluatie en eventuele bijsturing van het proces een goede actie. Best wordt hierbij ook het effect en de meerwaarde van deze bijkomende beschikbaarheidsinfo op het netbeheer in kaart gebracht, alsook de goede voorbeelden om deze taak op te nemen. Dit zal het draagvlak van deze verplichting verhogen en de implementatie vergemakkelijken. Het is goed voldoende tijd te voorzien voor de implementatie in de verschillende fases. Voor vele assets zal dit een nieuwe taak zijn. Vaak ook een administratieve taak die weinig te maken heeft met de primaire takenpakket van de asseteigenaar of beheerder. Om deze taak uit te voeren zullen de asseteigenaars of -beheerders technische aanpassingen moeten doen, hun werkplanning ver vooruit in kaart moeten brengen, mogelijks zelfs aanpassingen moeten doen aan hun werkproces. Eventueel zullen zij marktverkenning doen op zoek naar een professionele partner om deze OPA-taken op te nemen. Al deze acties zullen tijd in beslag nemen. Deze tijd moet voorzien worden in het implementatietraject in de verschillende fases. Ook zal er voldoende evaluatietijd nodig	

		zijn om ook de gewenste bijsturingen te kunnen doen alvorens over te stappen naar een volgende fase. Vermits er OPA's zullen zijn met assets in verschillende regio's is uniformiteit in implementatiedeadlines over de regio's heen aan te bevelen.	
Target go-live date	COGEN Vlaanderen	Regarding the scope of iCAROS phase 2 project, COGEN Vlaanderen currently estimates the number of relevant operational CHP-installations in Flanders to be around 397, representing a total capacity of 1306 MWe (estimation based on an internal analysis of a CHP inventory as received by VEKA for the year 2023). Based on the diversity of cogeneration installations and its users, a simple, user-friendly approach is needed, which is clear and manageable with a limited human and financial capital cost for the grid-user. Elements that could potentially contribute to this are, for example: - A phased roll-out of the implementation, during which the system can be evaluated and adjusted if needed (based on lessons learned). This seems useful given the high number and diversity of the units and Grid Users involved. - Each phase should foresee sufficient implementation time (in addition to the technical implementation time) since this Outage Planning will be new for many of the units and Grid Users involved.	The System Operators understand the worries of COGEN Vlaanderen, FEBEG and Febeliec and want to stress that the go live date of Q1 2027 is a target date. This date will be reviewed regularly to assess whether it remains realistic. Currently, assuming a formal consultation in Q1 2026, followed by a one year implementation, the go-live would now be foreseen in Q2 2027. This timing will be reassessed when needed, a first moment will certainly be after the finalization of the formal consultation. Regarding the request to have a phased roll-out, System Operators will propose to include an implementation plan in the regulated documents indicating that the design covers the full scope described in the design note (production and storage units till 1 MW and demand facilities directly connected to the ELIA grid) but that we foresee different waves in the on-boarding process: - Starting with the production and storage units till 5 MW and the demand facilities directly connected to the ELIA grid. - After a period of 6 months of normal operations, a return on experience (REX) will be foreseen. - If this REX is positive the on-boarding will be extended towards production and storage units till 1 MW. The System Operators are aware that the information requested is currently not delivered by these market parties. As such, System Operators will try to minimize the technical development needed at the side of the market party.

		Based on these elements, the proposed target of Go-live (Q1 2027) mentioned in the design note seems extremely ambitious.	This will be achieved by developing the system-to-system interfaces from the existing data exchanges for large units connected to the TSO grid. For B2C communication, accessible tools will be made available that market parties can easily use, without needing technical assistance. Additionally, the System Operators will expose to the market parties default information, modifiable in specific moments of the process with the purpose of simplifying the provision of the requested data. For instance, during the onboarding process, peak production/offtake over the previous year could be proposed by default as maximal active power production/offtake for the specific Delivery Point and the OPA could confirm or amend the value. Also, the System Operators will assess which support can be provided to the market parties during and after the implementation trajectory. Currently, (online) information/training sessions and a dedicated functional mailbox are being considered. Furthermore, System Operators are committed to ensuring effective preparation by making all relevant technical documentation available to market parties well in advance of key milestones in the implementation process. The aim is to provide sufficient time for review and familiarization, supporting a smooth transition and informed participation. Specific timelines for the release of these documents will be communicated proactively as the project progresses, ensuring market parties have clarity as they prepare for the new obligations.
	FEBEG	The proposed target go-live (Q1 2027) appears unrealistic. The time between design discussions, consultations, regulatory processes, contractual onboarding, and IT development is too short. Technical requirements are not yet detailed, and the implementation burden for small units is underestimated. Indeed, many technical details still need to be clarified. For instance, how to deal with sites that have a backup connection connected to another grid? When the technical requirements are completely finalized, an implementation period of at least 1 year needs to be foreseen. Introducing a non-mandatory transition period might give extra flexibility to manage the required changes. In that way information can already be provided for those assets that are ready with the implementation of this obligation.	
	Febeliec	Regarding the proposed timeline of onboarding of outage responsible parties in Q1 2027, Febeliec insists that this will only be possible insofar a.o. clear requirements and tools will be made available in due time to ensure a successful implementation. Febeliec wants to stress that most of the parties who will have to comply with these new requirements regarding outage planning have up till now not had such obligations and would have to start implementing from zero. Moreover, due to the number of new actors with obligations, it is important that scalability is taken into account, including helpdesks and	

		IT support to ensure a successful onboarding and/or transition.	

4.3 Business process comments

Subject	Stakeholder	Feedback received	System Operators' view
Business process alignment between regions	EDORA	EDORA suggests aligning the OPA plannings between the different regions to facilitate communication as many customers have assets in multiple regions.	The System Operators confirm the objective of having an aligned business process for all related Outage Planning Agent (OPA) processes that will be described in the regulated documents, namely the individual System Operator regulated contractual documents. The Closed Distribution System Operators will reuse for their Closed Distribution System Users the T&C OPA applicable for the TSO's OPAs.
Proposed business process not aligned with reality of smaller assets	FEBEG	In general, and not only for RES, maintenance planning process for small assets is largely outsourced, inflexible and intrinsically uncertain. Last-minute changes to the maintenance planning due to maintenance staff availability, emergencies, etc. occur often in reality. The outage planning will inevitably be inaccurate. The proposed validation process (e.g. from W-12 onwards) conflicts with this operational and contractual reality. […] FEBEG acknowledges that for larger units (≥25 MW), participation in outage planning is already mandatory and necessary for system transparency. However, extending this obligation to much smaller units should not introduce constraints that are impossible to comply with given their specificities.	Several stakeholders provided aligned feedbacks stating that the currently proposed deadline for the provision of the preliminary availability plan defined on W-12 does not match with the reality of smaller assets in terms of maintenance planning. As such, an alternative proposal with amended business process is introduced in the updated design. To incorporate the feedback that reliable information can only be delivered by the Outage Planning Agents (OPAs) to the System Operators starting from one month in advance, for production and storage facilities of size greater or equal than 1 MW, the original deadline of W-12 is moved to (Friday) W-5. This date is chosen to align the deadline for the preliminary availability plan creation with the System Operators' operational process, where for example in Elia regional transmission network the planning of grid outages for the upcoming 4 weeks is performed. Additionally, a new change is included between 1st of August Y-1 and Friday W-5 explained hereunder.
	COGEN Vlaanderen	COGEN Vlaanderen would like to point that also between Monday week-12 and Real Time minus 45min, unforeseen or	

		uncontrollable events might occur, leading to the fact that the OPA would need to change its availability plan. The production profile of a CHP-installation is also influenced by the economic activity of where it is located and the resulting electricity, heat and/or CO_2 demand, or the need to process certain fuels (e.g. biogas production, energetic valorisation of (biomass) waste, syngas, etc.). In the window between Monday week-12 and Real-Time minus 45 min, unforeseen events might also occur such as: - Unforeseen changes with regards to the economic activity on the site where a CHP is located (e.g. the unforeseen (partial) outage of a production line, affecting local heat demand, or disruptions/changes in the availability of certain fuels coupled to the economic activity on site (e.g. biogas production, energetic valorisation of (biomass) waste, syngas, etc.). - Unforeseen changes in maintenance planning, which is largely performed by a third party, resulting in a maintenance planning process which can be inflexible and uncertain. As the proposed validation process conflicts with this operational and contractual reality, COGEN Vlaanderen stresses the need for a pragmatic, realistic, and cost-efficient implementation, that does not introduce constraints that are impossible to comply with and which acknowledges the complexity and costs associated with CHP-installations	Here a summary of the main steps of the amended simplified business process: 1. 1st of January Y-3: Automatic creation of the long-term indicative availability plan and from this moment onward, OPAs can start submitting data to the system. No mandatory participation is expected at this stage and any submitted change to the long-term indicative availability plan will be automatically accepted by the system. 2. 1st of August Y-1 is the deadline for the creation of the year-ahead indicative availability plan. As of this moment, participation is mandatory and known information about planned maintenance or reduction in P_{max} shall be communicated to the System Operator. Based on the feedback received from the market parties a new concept of "blocked periods" is introduced. Market parties suggested that if System Operators indicate the periods where the maintenance of the Technical Facility would be problematic from the System Operators' point of view (i.e., due to maintenance on the grid), the OPA could take information into account when planning the maintenance of its Technical Facility. The proposed change in the business process would be that starting from the 1st of August Y-1 System Operators, only when relevant and needed, would indicate to the OPAs the defined "blocked periods" per delivery point. During these defined "blocked periods", if OPAs would submit new planned unavailabilities, these changes to the availability plan will not be automatically accepted, instead they will trigger a standard change request process. It is also applicable for submitted changes (partially) overlapping one or multiple "blocked period". On the other hand, any submitted change to the availability plan outside of these "blocked periods" would be automatically accepted by the system.
	Bnewable	In de huidige benadering wordt er voor installaties van 1MW eenzelfde werklast gegeneerd als voor grote installaties. Dit betekent dat voor de kleine installaties zowel bij de DNB's en TSO'	

		als bij de "outage planningsagenten " en werklast ontstaat dikwijls zonder zichtbaar impact op het net. Het lijkt ons efficiënter om in het planningsproces een extra stap toe te voegen. Als de DSO 's en TSO inzage geven in de geplande outageplanning van de assets waar de installatie met verplichte deelname op aangesloten is, kan de outage planningsagent zich zoveel als mogelijk aligneren. Dit vermijd extra afstemming en ook extra onbeschikbaarheden als gevolg van outages geïnitieerd door de netbeheerders. De stappen in het proces zijn dan: 1. De TSO en DSO plannen een voorstel van onbeschikbaarheid op het netsegment waar de assets met verplichte deelname op aangesloten zijn. 2. Automatische creatie van indicatieve lange termijn onbeschikbaarheid (preset = beschikbaarheid van de installaties). 3. Indienen van veranderingen in de onbeschikbaarheden door de outage planningsagenten. 4. Update van de beschikbaarheidsplannen	3. Friday W-5 is the deadline for the creation of the preliminary availability plan. As of this moment, known availability plan(s) become(s) binding and changes submitted by the OPAs will trigger the standard change request process, whether there is (partial) overlap with a "blocked period" or not[1]. 4. From 45 minutes before Real time only Forced Outages events can be declared by the OPAs, and they will be automatically accepted by the system. The business process applicable to the demand sites is also amended similarly to the one described above for the production and energy storage facilities, with the difference that from Friday W-5, the preliminary availability plan does not become binding, and any changes submitted by the OPAs after that gate will still be accepted automatically under all circumstances without triggering a change request process. The "blocked periods" are therefore exposed to the demand sites' OPAs for information and do not change anything from the originally proposed business process. Nonetheless, as those "blocked periods" are exposed to the OPAs for reasons of operational security risks, avoiding submitting changes within those periods would remain recommended. These proposed modifications seem to provide enough relaxation to the initially proposed process and with the additional information exposed to the OPAs by the System Operators, at least one or all validation iteration could be avoided by making usage of the information of the "blocked periods".
	ODE	Voor meerdere kleinere assets en hernieuwbare energie-assets zal dit een aanpassing betekenen ten opzichte van hun bestaande werking. Voor deze assets liggen de onderhoudsmomenten vaak nog niet lang op voorhand vast. Soms wordt het beheer door externe service providers gedaan waardoor ze niet de volledige controle hebben over het moment waarop het onderhoud effectief zal plaatsvinden. In het proces zou er voor hen	

[1] Some newly defined exceptional scenarios will conditionally bypass the regular change request process.

		voldoende flexibiliteit moeten voorzien worden. Deze flexibiliteit zal het draagvlak ook wel kunnen vergroten.	
Indicative information send with more than one month notice	Aquiris	Il nous est déjà complexe de communiquer correctement pour la flexibilité aFFR, qui est pourtant rémunérée. Aussi, notre usine (station d'épuration) est particulièrement sensible aux conditions extérieures. Tout planning communiqué plus d'un mois à l'avance sera donc principalement indicatif.	The proposed changes to the business process described in the previous answer (subject "*Proposed business process not aligned with reality of smaller assets*") should be more aligned to the smaller assets' operational reality and should provide more comfort to the OPA for the submission of the requested information. Furthermore, any information, even indicative, is valuable for the System Operator for anticipating any potential operational security risk.
Change request timeline applicability for smaller assets	FEBEG	For small RES, there is currently no feedback loop between Grid User, service provider, and SOs. Implementing one would require extensive change management and dedicated resources, which are not in place today. The fact that the SO can reject a change in maintenance planning before day-ahead will greatly complicate the maintenance planning for these small assets and needs to be revised.	The proposed changes to the business process described in the previous answer (c.f. subject "*Proposed business process not aligned with reality of smaller assets*") and corresponding exposure to the OPA by the System Operators of the "blocked periods" provide additional comfort to the OPA to submit changes closer to real-time. Changes submitted outside of the blocked periods, still subject to the change request process after Friday W-5, will have a higher probability to be accepted by the System Operator.
Change request acceptable compensation components	COGEN Vlaanderen	The potentially associated costs related to the acceptance of a change request should be interpreted in a broader context than merely related to the electricity consumption or production of the Grid User. The production profile of a CHP-installation is not only influenced by the production (and local consumption) of electricity, but also by other driving factors such as heat and/or CO2 demand, other assets at its disposal, or the need to process certain fuels coupled to the economic activity on site (e.g. biogas production, energetic valorisation of (biomass) waste, syngas, etc.). These elements should also be valid parameters when providing an offer to the system operator.	The foreseen specifications in the design and the contractual documents are large enough to include the costs mentioned for a CHP-installation, as long as the costs are reasonable, demonstratable and directly related to the request, in case a System Operator would request a modification of an already accepted planned unavailability., The costs will be considered as acceptable when providing an offer for the requested modification of the planned unavailability.
General comments on proposed business process	FEBEG	• The process assumes centralized control and dispatchability, which does not apply to most wind and solar installations.	The outage planning coordination process does not assume centralized control and dispatchability. In fact, it does not impose any requirement concerning direct control or dispatchability by the System Operator on wind and solar installations,

		• For RES, maintenance is frequently outsourced under long-term contracts, with service providers retaining the right to schedule interventions. Asset owners may not be able to adjust outage timing to accommodate SO requests. This contractual reality must be reflected in the process design. • Furthermore, the added value of updating the outage planning for solar panels is questionable. Those assets are almost always 'Available'. Updating the availability status will only become necessary after a defect is detected (1 time every x years), in which case the asset has a forced outage for an extended period, i.e., until the defect is resolved.	but only to communicate planned unavailabilities or restrictions that could affect the networks operational security. The initial business process design is updated to accommodate the timing specificities of the smaller assets as described in the answer with subject "*Proposed business process not aligned with reality of smaller assets*". By postponing from W-12 to Friday W-5 the start of the "binding" availability plan and by introducing and exposing "blocked periods" to the OPAs it is considered that the introduced adaptions provide sufficient relaxation and information to the OPA to plan maintenances accordingly. It is reminded that the availability of an asset is by default considered as "Available" until communicated differently by the OPA. It may be that for solar parks, the default availability plan would remain applicable the entire year Y if no relevant event leads to the change of its status or $P_{max,available}$. Therefore, in such case no effort is requested by the OPA until the occurrence of a relevant event.

4.4 Target scope and associated obligations comments

Subject	Stakeholder	Feedback received	System Operators' view
Benefits	Febeliec	Febeliec wants to stress that the benefits would be in first order only for the system operators, in parallel creating additional costs and complexities for grid users, while only in second order the grid users might benefit from this through potentially lower system costs, insofar their data is used in a beneficial way by grid operators in a.o. grid operations, grid planning and grid investments. In particular in DSO grids, it should be taken into account that demand has no outage planning obligations (for good reasons any such obligations were not withheld in European legislation) and as such the available information would only be partial in any case. Insofar possible, Febeliec urges towards an	As stated in article 52 of SOGL "*1. Unless otherwise provided by the TSO, each transmission-connected demand facility owner shall provide the following structural data to the TSO [...] & 2. 2.Unless otherwise provided by the TSO, each transmission-connected demand facility owner shall provide the following data to the TSO [...]*" the TSO may request outage planning information if needed for operational security reasons. As such, the objective is to collect information regarding the availability of the transmission-connected demand facilities and especially the planned evolutions of the P_{max}, given this information can be used to significantly improve the quality of the operational security analysis.

		approach that is as synergetic and positive for all parties as possible, to ensure grid security while limiting costs for grid users.	To simplify the process for the Grid Users, the P_{max} is defined as the maximum offtake of this demand site during the Year Y. If no extensions or fundamental changes in the activities of the demand site are foreseen, a good proxy for P_{max} over the year Y could be the peak offtake of year Y-1. The OPA will be able to define a specific date from which an eventual modification of the P_{max} should apply for the availability plan. By providing the information of the reduction of maximal active power offtake or by declaring a status Unavailable (granularity from Friday W-5 should be at least on a daily level), the System Operator can anticipate changes in offtake patterns to refine the information used in the operational security analyses and improve the precision of its results to anticipate better operational security risks. It is important remember that for demand facilities no validation is required whatever the time and the information the information is sent it will be accepted without validation from Elia. Elia can, however, request a change towards the OPA that the OPA is free to accept or refuse. For the sake of simplicity, the Delivery point for a demand facility is by default defined to the connection point, while, if relevant, a split up per juridical entity could be requested. Demand facility connected through a CDSO to the transmission grid are not in scope of the current design. This request is limited to TSO-connected demand facilities and therefore fully compliant with the SOGL regulation. These simplifications and default assumptions, with possibilities of amendments at any moment in time by the OPA, are introduced to minimize the efforts and costs from the Grid User/OPA. Additionally, the scope is only limited to a directly transmission connected demand sites;
Applicable statuses for demand facilities	Febeliec	Regarding the proposed states, Febeliec asks for a clear definition, especially towards "Unavailable" (versus forced outage) and "Testing" for demand facilities, to ensure that the scope is unambiguously clear. It is clear that demand facilities will, while being available, not necessarily be consuming at their nameplate	For demand facilities, the different statuses accepted for the availability plans will be reduced to Available and Unavailable. The status reflects each time the evolution compared to the defined P_{max} for the year Y. The P_{max} of a demand site is the maximum expected offtake for year Y.

		capacity and as such it should be clear which data in which scope should be communicated, in particular also when there is on the (industrial) sites a mix of demand, generation and storage (and for the latter two assets above and below the 1MW thresholds). This is also very relevant towards the concrete data perimeters, as it will need to be unambiguously clear whether consumption data or offtake data will have to be provided, and for the distinction between those how certain assets (e.g. generation and storage smaller than 1 MW) need to be accounted for and allocated to a specific perimeter.	A non-exhaustive list of scenarios is proposed here to explain what should be declared in which way: • Offtake below P_{max} for year Y due to partial maintenance or reduced economic activities: status is defined to “Available”, with $P_{max,available} < P_{max}$ (i.e., maximum offtake in year Y) • Total shutdown due to planned maintenance: status is defined to “Unavailable”, with $P_{max,available} =$ 0 MW • Planned process shutdown (full): status is defined to “Unavailable”, with $P_{max,available} =$ 0 MW • Partial planned process shutdown: status is defined to “Available”, with $0 < P_{max,available} < P_{max}$ Concerning the question of offtake versus consumption data to be provided, as the availability plan is defined at the level of the Technical Facility itself, for demand, the information expected relates to its net offtake of the industrial site at the connection point to the SO's network. Production and storage units with an installed capacity of 1 MW and more need to deliver information separately. For sake of clarity emergency and process generators (as defined in Article 3(2) point (b) and (c) of the Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators are excluded from this obligation. This exemption is also extended to energy storage facilities used in the same purpose, as already translated in Article 2. §2 1° of the Federal Grid Code.
Units’ aggregation & definition of availability plan at delivery point level		Bij een eerste lezing van de documenten, kwamen de volgende vragen alvast naar boven: 1. Een Site (=1 delivery point) met daarop aangesloten: 0,7 MW Wind, 0,6MW Solar en 0,5 MW Batterij moet deze deelnemen? Ik denk ja, omdat totaal vermogen > 1MW	For a site including 0.7 MW produced by a wind park, 0.6 MW by a solar park, and 0.5 MW by a battery, the following characteristics would apply: • Three different Power Park Modules (PPM) would be defined, one for each primary energy source (wind, solar, electrical storage).

		is. Moet deze voor dat Delivery Point 3 verschillende schema's doorsturen? Nl. per Primary Energy Source 1? 2. In de praktijk zal dit (voor Solar en Batterij) toch gewoon neerkomen op éénmalig een 3 jaar 100% available inschieten en dan enkel nog de forced outages zo snel mogelijk rapporteren? Waarom kan de TSO/DSO dat dan niet zelf via de reeds verplichte telecontrole + registratie van de assets vaststellen?	• Each of the PPM is considered a Technical Facility (TF) of its own. • As the obligation to participate to the outage planning coordination process is assessed at TF level, none of the three TF would be within the range requiring a mandatory participation (≥1 MW). The PPM associated to the wind park in the example above, will contain the aggregated information of all individual wind turbines behind the same access point, same is applicable for any non-synchronously connected device. The System Operators are therefore not asking to provide information of each individual wind turbine, solar panel, or battery, instead, by default, it is requested to exchange the availability information at PPM level, which is an aggregation of all non-synchronously connected devices per primary energy source. Now assuming each TF would be above the 1 MW threshold (or the Grid User would like to voluntarily participate to the outage planning coordination process for all three TFs): • For each TF, one Delivery Point (DP) would be defined • Three availability plans shall then be defined, one for each DP/TF. For each DP defined (1 for each TF, with previous example assuming threshold is exceeded, three TF/DP shall be defined), on the 1st of January Y-3, an availability plan with 100% availability for the year Y would indeed be defined by default by the System Operators. Then it would be up to the Outage Planning Agent to communicate any planned maintenance, planned tests, or reduction in maximal active power in offtake/injection to the System Operators. Forced Outage declaration would be only limited to unplanned unavailability of a specific TF, so only acceptable to be declared closer to real-time, otherwise it shall be considered as a planned maintenance. The System Operators could indeed determine the availability of the TF by checking measurements for the assets (which is anyway performed) but would not serve any of the purposes listed in the Chapter 5 – Understanding Outage
	Ventis SA	En tant que responsable d'exploitation pour la société Ventis, qui exploite actuellement une septantaine d'éoliennes en Belgique (toutes d'une puissance supérieure à 1 MW), je souhaite vous faire part de nos remarques concernant la note de conception relative à la coordination des indisponibilités. Dans notre cas, le volume d'unités concernées est particulièrement important, et nous faisons face quotidiennement à de multiples événements d'indisponibilité : • Indisponibilités non planifiées : pannes imprévues nécessitant des interventions correctives. • Maintenances planifiées : dont la programmation reste très incertaine, car elle dépend de la disponibilité des équipes du turbinier, des priorités liées à d'autres pannes urgentes, ainsi que de conditions météorologiques souvent changeantes (par exemple, impossibilité d'intervenir en cas de vents trop forts, entraînant l'annulation ou le report d'interventions prévues). Dans ce contexte, l'obligation de signaler chaque arrêt, planifié ou imprévu, au niveau de chaque éolienne individuelle représenterait pour notre société une charge de travail considérable, mobilisant en permanence nos équipes	

		opérationnelles. Cet effort administratif risque de détourner des ressources qui devraient avant tout être consacrées à la sécurité et à l'efficacité du fonctionnement de nos installations. Nous comprenons pleinement les objectifs de ce processus ; améliorer la transparence, la coordination et la sécurité du réseau électrique, et nous y adhérons sur le principe. Néanmoins, nous considérons qu'une approche plus pragmatique et proportionnée est nécessaire pour les exploitants disposant d'un grand nombre d'unités de production décentralisées, comme c'est le cas pour les parcs éoliens. À titre de piste d'amélioration, nous suggérons : • de privilégier une agrégation des indisponibilités (par parc ou par site), plutôt que le suivi détaillé de chaque turbine prise individuellement • ou encore de définir des seuils de durée ou de puissance indisponible en deçà desquels aucune déclaration immédiate n'est requise, Nous vous remercions de prendre en considération ces éléments pratiques. Nous restons à votre disposition pour discuter d'une adaptation du processus qui réponde aux objectifs de coordination tout en restant réaliste et applicable pour les exploitants de parcs éoliens.	Planning of the document "*Design note for Outage planning coordination for small production and energy storage units connected to TSO/DSO grid and TSO connected demand site* ". In fact, as mentioned in the document, a certain number of studies/analyses are performed years/months/days in advance, to timely identify any potential issue arising in the transmission/distribution networks from planned maintenances and to align as much as possible maintenance of network elements to the ones from the Grid User's to reduce disruptions for them. As regular simulations are performed starting from several years in advance, obtaining more accurate information, when available, would improve significantly the accuracy of the results, allowing better planning and more economical solutions to resolve any potential issue. Identifying the planned unavailability only when it is occurring does not allow to timely find the most optimal solutions economically (last minute maintenance rescheduling, network congestions requiring costly remedial actions, ...) and on some occasions might also disrupt the Grid User's activities if no better solution is available. Therefore, the goal is to receive in advance any information known by the OPA in terms of changes in availability, so that the SOs can incorporate this additional information in their studies and more precisely anticipate potential risks to the grid security. Regarding the minimal threshold in duration or Pmax reduction to submit a change to the availability plan, for operational security point of view, the minimal length would be of a quarter-hour, while the minimal Pmax change would be of 0.1 MW. Based on the return of experience of each onboarding wave, such thresholds could be revised if deemed necessary.
Grid User assigned as OPA or assigning the OPA	FEBEG	The obligation for Grid Users to appoint an OPA—or to act as OPA by default—requires extensive communication and change management. Many affected parties are not yet familiar with these obligations and will need guidance.	Now a communication plan listing several actions to onboard and inform the new OPAs impacted by the extension of the scope of the OPA design is not available. However, the involved System Operators are aware of the need to have such a plan and will put into place a communication plan at the start of the implementation of the extension of the design that focus on creating awareness of the new obligations as well as support to enable these new OPAs to comply

<table>
<tr><td></td><td></td><td></td><td>with these new obligations. Furthermore, it was already identified that this will be an on-going activity given the recurrent task of on-boarding new OPAs.</td></tr>
<tr><td rowspan="2">Process complexity</td><td>Febeliec</td><td>Febeliec would like to stress that the level of outage planning requested towards the future for TSO-connected demand sites as well as for smaller production and storage units will have a major impact on industrial consumers, who historically did not have to comply with all these evermore strict data requirements and obligations. While Febeliec understands that grid operators need to have a better view on the assets in their grids and their behavior, a.o. due to the increasing impact of intermittent generation, active storage use and demand side response, the level of additional requirements towards grid users has to be balanced with the benefits that these could bring.</td><td rowspan="2">The System Operators are very aware that requesting these data entails additional effort from the side of the Grid Users. As such they opted for a phased implementation within iCAROS, starting with requesting only outage planning information for the Grid Users not used to comply with these data requirements.

Furthermore, based on the feedback received during the informal consultation, the design was simplified and particularly the data delivery timing was tailored to comply with the operational framework of these smaller units and demand facilities. Given the indication of market parties that they are not aware of specific timings of planned unavailabilities one month before real time, and the suggestion of market parties that the System Operators could give insights in their maintenance planning, a new design feature was introduced, namely “blocked periods” as described in the answer with subject “Proposed business process not aligned with reality of smaller assets”. In this way, the OPA knows that receiving a validation for a planned unavailability, for production and storage facilities, submitted during or overlapping a blocked period becomes very unlikely. As such OPAs can transmit this information to the party in charge of the maintenance on their assets. Furthermore, for demand facilities the relevant statuses were reduced to 2 (Available with P_{max} limitation and Unavailable).

Furthermore, the process of submitting outage information is simplified for OPAs by providing a single point of entry to communicate outage-related data to all System Operators, provided that operational security is maintained. The system will use prefilled default outage data, which OPAs can modify as needed.

Additionally, similarly as for the production and energy storage facilities, the business process was updated and simplified for demand facilities as well:

1. On 1st of January Y-3 the long-term indicative availability plan is created automatically by the system. By default, each Demand Facility is assumed to be available for the entire period of Year Y, and the default maximum active power P_{max} will be defined based on the OPA’s configuration. At</td></tr>
<tr><td>COGEN Vlaanderen</td><td>Not every site containing a CHP-installation has a fulltime Energy Manager who is familiar with the ins and outs of the energy markets and other related aspects. Irrespective of the fact if this is the case, the role of OPA will be an additional task to be taken on by the Grid User, or outsourced to a third party.

[...]

If the chosen approach would end up to be to complex or to human and/or financial capital cost intensive, this might negatively influence CHP-installations. As we already previously mentioned in former public consultations (e.g. Elia public consultation on the Adequacy and Flexibility study2 or the Elia/Fluxys public consultation on the Federal Development Plans), we expect a decrease in CHP capacity in Flanders for the coming years. This expectation is based on the current policy framework (combination of European, Federal and Flemish elements), although these installations contribute to primary</td></tr>
</table>

		energy savings, renewable energy production, security-of-supply and flexibility needs of the Belgian society and its Regions.	first it will depend on the value introduced during the onboarding process, which by default for existing demand facilities will be proposed as the known peak offtake of the year preceding the onboarding date. For new demand facilities, the default value proposed during the onboarding will correspond to the PPAD value. Then, for subsequent long-term indicative availability planning creation, the default value will correspond to the declared P_{max} of the preceding year. This default value can be modified at any time by the OPA. As of this moment no mandatory participation is expected, any submitted change to the long-term indicative availability plan is automatically accepted. 2. 1st of August Y-1 is the deadline for the creation of the year-ahead indicative availability plan. By this deadline, the OPA is requested to communicate its P_{max} reference value for the year Y. From this moment, participation is mandatory and, known information about planned maintenance or reduction in P_{max} shall be communicated to the System Operator. P_{max} or status updates shall be announced by the OPA at least with a monthly granularity, but finer resolution will also be accepted. The OPA can opt to declare a P_{max} update either as a percentage of the P_{max} or as an absolute MW value. Already a high-level indication of a month with a particular reduction will already be very appreciated and valuable for the System Operators. Additionally, based on the feedback of market parties, the new concept of “blocked periods” is introduced as described in the answer with subject “*Proposed business process not aligned with reality of smaller assets*”. For Demand Facilities, these blocked periods are also exposed for information to the OPA despite not having any impact on the business process, as any change to the availability plan submitted for demand facilities will be automatically accepted without any validation from the System Operators. Nonetheless, on a best-effort basis, the OPA should try to minimize introducing changes of status or reduction of Pmax

			(partially) overlapping with already defined blocked periods, as they will have a significant impact on the System Operators' operations. 3. From Friday W-12 any changes to the availability plan submitted by the OPA is limited to a weekly granularity with finer granularities accepted. 4. Friday W-5 is the deadline for preliminary availability plan definition. As of this moment, changes to the availability plan submitted by the OPA is limited to a daily granularity with finer granularities accepted.
Run-of-river generation specificities and obligations		Nous exploitons 8 centrales hydroélectriques sur la Meuse d'une puissance unitaire inférieure à 3 MW. Nous sommes tributaires du débit de la Meuse et nous ne savons pas le prévoir à long terme. Même à court terme, sur une journée, le débit peut varier et faire varier notre puissance. Nous attendons que les débits soient les plus faibles possibles pour effectuer les arrêts de maintenance et ils ne sont donc pas planifiés à l'avance. Il n'est donc pas possible pour nous de prévoir les indisponibilités à long terme, ni même à court terme. Nous avons aussi des évènements imprévus qui conduisent à des arrêts ou des réductions de puissance comme les déchets qui obstruent les grilles. Nous demandons donc à ne pas être repris dans la coordination des indisponibilités. Si la règlementation ne s'appliquait qu'aux installations supérieures à 3 MW, nous ne serions plus concerné. Ou alors, pourriez-vous nous octroyer une dérogation?	System Operators understand the complexity coming from the described business process. Based on the feedback received during the public consultation simplifications to the business process were performed to comply with the operational reality of the targeted grid users as described in the answer with subject "*Proposed business process not aligned with reality of smaller assets*". Nonetheless, as the obligations are coming from European, Federal and regional regulation, and needed for operational security, as such System Operators cannot support the request for a derogation. Regarding the specific reality of run-of-river hydropower plants, changes occurring very close to real time (outage or active power reduction) can be declared via a partial or full Forced Outage. Based on other comments received, a new parameter is also foreseen to declare unavailability events that are not strictly related to technical issues or maintenance.
Obligation for assets below 5 MVA	Bnewable	Voor installaties aangesloten op het DSO net lijkt de grens van 5MVA meer aangewezen, Deze vermogensklasse is ook aangesloten als een 1-26 KV post aansluiting aan de impact op het koppelpunt is dan ook direct waarneembaar. Anderzijds is de impact vanuit de groep laagspanningklanten veel sterker dan de groep van de ingeluste klanten (1-26 KV net). Bij de ingeluste (1-26KV net) klanten dient de batterij meer voor optimalisatie van	Regarding the request to have a phased roll-out, System Operators will investigate to include an implementation plan in the regulated documents that indicate that the design is for the full scope mentioned in the design note (production and storage units till 1 MW and demand facilities directly connected to the ELIA grid) but that we foresee different waves of on-boarding starting with the production and storage units till 5 MW and the demand facilities directly connected to the ELIA grid. After a period of 6 months of normal operation a

		het eigen verbruik van de site en zal de outage hierop afgestemd worden waardoor netimpact van de outage verwaarloosbaar is.	return on experience will be foreseen and if this evaluation is positive the on-boarding will be extended towards production and storage units till 1 MW.
Demand facilities' obligations	FEBEG	For very large demand facilities, FEBEG supports the principle of providing maximum transparency on availability and expected Pmax. These grid users are typically experienced market participants (active in forward, spot, and even real-time markets) and can provide valuable, reliable information to support system operation without incurring costs. However, FEBEG notes that according to the design note, availability information from demand sites remains indicative and does not require validation by the SO. This risks to undermine the reliability of the data, even though accurate and dependable information is essential when such large offtake units are concerned.	It would not be correct to apply the same rules to demand facilities as to production units given the later does not pay any access tariff while demand facilities do. More specifically they pay a recurrent fee for the availability of a particular connection capacity. As such a follow-up of the correctness of the transferred information can be set-up but changes in the availability information itself cannot be blocked given this type of Grid User are paying a recurrent fee for the access to the grid.
E-boiler scope clarification	ODE	Ten slotte vragen we nog even een verduidelijking rond de scope van deze verplichting: als we spreken over productie- en energieopslagsystemen met een vermogen tussen 1MW en 25MW, gaat het hier bij energieopslagsystemen enkel over batterij-opslag. Groot vermogen e-boilers die ook energie kunnen opslaan, zitten niet in scoop. Kan dit bevestigd worden ?	E-boilers being assets only consuming electrical energy are categorized as demand. Demand facilities are in scope of this process for the ones directly connected to the TSO network or connected to a CDS network also connected to the TSO network.

4.5 Information flow comments

Subject	Stakeholder	Feedback received	System Operators' view
	EDORA	EDORA welcomes also the single-entry for the OPA to provide information for its entire portfolio which will facilitate	System Operators foresee a single interface for exchange of the entire portfolio of outage information, but with additional (backup) channels for units that are

Need for a user-friendly interface		communication. It will ease its work by being able to do so, even more if regardless of which grid the asset is connected to.	important to operational security. The solution will provide the ability to deliver and access outage information through a single interface provided that operational security is maintained. This interface will include prefilled default outage data that OPAs can easily review and adjust as necessary. Consistent with our aim to maximize alignment with existing interfaces, Grid Users and OPAs with only Elia and CDS-connected assets, the existing interfaces will be as much as possible aligned with existing protocols and message formats. The information provided for larger units is today already used by the TSO also to fulfill transparency obligations and to check compliance with CRM obligations. It is also foreseen to use this in the framework of the MVAr product if relevant. It will also be assessed, once insights are obtained regarding the quality of the received information, how the OPA information from small units and demand facilities directly connected to the TSO grid could be used further than for the reasons described in the design note.
	Febeliec	Core principles should be the possibility to re-use data, which should only be provided in a single instance (and then communicated to all relevant system operators), if possible in a multi-purpose approach (even beyond the scope of outage planning) and in an as user-friendly way as possible, in order to ensure that the data quality (and thus the resulting information) should be as robust and useful as possible under the lowest possible system cost.	
	COGEN Vlaanderen	Based on the diversity of cogeneration installations and its users, a simple, user-friendly approach is needed, which is clear and manageable with a limited human and financial capital cost for the grid-user. Elements that could potentially contribute to this are, for example: • Provision to make the information flow easy and compatible with existing information and management tools used by Grid Users or OPA's. For an OPA with multiple Grid Users, this will become a regular task, possibly involving certain automations. For an individual network user who wishes to take on the OPA role themselves, a simple delivery method will be important. • The proposed single entry (so that OPA's may communicate information for their whole portfolio across all regions and voltage levels), as well as the proposed flexibility in communication channels (user	

		interface or system-to-system interface) to ease the information exchange for the OPA's.	
	ODE	Deze verplichting om outage-planning door te geven zal zorgen voor bijkomende administratie bij de betrokken netgebruikers. Om die reden is het wenselijk de werkwijze van gegevensoverdracht zo eenvoudig en gebruiksvriendelijk mogelijk te houden. In de scope zitten verschillende soorten assets die elk op hun manier - al dan niet geautomatiseerd - beheerd worden. Om die reden is het noodzakelijk om flexibel met de opgelegde overdrachtmethode – ook al dan niet geautomatiseerd - om de gaan. Er zullen ook partners of OPA's met meerdere assets in hun beheer zijn. Voor hen zal het belangrijk zijn om één single entry point te hebben voor de communicatie van de informatie voor alle assets waarvoor hij verantwoordelijk is. Er moet een streven zijn naar uniformiteit in de werking, onafhankelijk of het asset op het distributie- of transmissienet aangesloten is. Een uniformiteit met de bestaande verplichting rond Outage-planning voor vermogens groter dan 25 MW is aan te bevelen.	

4.6 Availability plan statuses comments

Subject	Stakeholder	Feedback received	System Operators' view
RES external constraints	EDORA	Maintenance times are carried out via service providers, which means that the grid user does not have complete control over when	

impacting availability plan		the maintenance takes place. The timing of scheduled maintenance remains highly uncertain, as it depends on the availability of turbine maintenance teams, priorities related to other urgent breakdowns, as well as often changing weather conditions (e.g. inability to intervene in the event of high winds, resulting in the cancellation or postponement of planned interventions). As it is difficult to provide accurate information for small RES installations, flexibility is needed for them and should be considered in the processes. Moreover, the unplanned availabilities of RES assets could be frequent due to different events (weather conditions, ice, bird protection, respect for shadow norms, curtailments, etc). Their specific reality should be considered by allowing some flexibility in the unavailability definition.	In case the Grid User would not be the OPA, modalities will be put in place to view the information entered in the system on its behalf by the designated OPA as depicted in Figure 18 of the design note. Based on the received feedback the business process was updated to be more suited to the reality of the smaller assets, with a deadline for the submission of the preliminary availability plan moved to Friday W-5 instead of W-12. Additionally, the System Operator will indicate before Friday W-5 the "blocking periods", as described in the answer with subject "*Proposed business process not aligned with reality of smaller assets*" where new maintenances of Grid Users' assets cannot be planned. Finally, for the window between Friday W-5 till close to real-time, new unavailability events or updates of existing unavailability events (cancellation or postponement) can always be submitted by the OPA prior to 45 minutes before real-time. Such changes will be assessed and validated by the SO in due time. To increase the success rate of acceptance of a newly submitted unavailability event or of the change request of an existing unavailability event, the concept of "blocking period" was introduced indicating the periods that could more probably result in a refusal. In fact, these "blocking periods" indicate the timespans when the System Operators count on the presence of the technical facility for the operational security of the grid.
	FEBEG	The design note foresees the use of the standard SOGL statuses (A/U/T/FO). However, for renewable assets, unavailability can also stem from environmental or regulatory constraints (e.g. icing, bat protection, bird migration, shadow, curtailments). These should be considered explicitly as availability statuses to avoid misinterpretation. Therefore FEBEG suggests to clarify the definition of "outage". "Outage" should only refer to major cases such as substation maintenance or a serious failure that keeps an asset offline for an extended period.	To differentiate the mentioned environmental and regulatory constraints, a new parameter is proposed to be included when submitting unavailability events to the System Operator. This additional parameter will allow to differentiate strictly energy related restrictions (availability of primary energy or technical interventions on the technical facility) with environmental (icing, bats/bird protection, weather conditions) and regulatory/permit (shadow, noise restrictions, birds/bats protection, ...) related constraints. Based on the understanding of the mentioned non-energy related constraints, some precisions are provided to guide the OPA to submit the information to the System Operators.

			Regulatory or permit related restrictions known from construction permits, such as noise restrictions, can be communicated in advance to the System Operator by sharing, under assumption of optimal conditions, the following: • Indicating the “non-energy related” nature of the event via the specific parameter • Available status • Corresponding time windows leading to $P_{max,available}$ limitations The submission of such recurrent restrictions will be made possible in a user-friendly way, limiting the efforts from the OPA. For restrictions identified only closer to real-time, relaxations to the change requests approval process are considered for “non-energy” related events: • For further $P_{max,available}$ limitations without a change in status (Available), imposed by regulatory/permit constraints it is proposed to use the new parameter allowing the information to be automatically accepted, without requiring a validation from the System Operator. • For unplanned unavailabilities originated by regulatory/permit reasons, such as the shadow flickering, it is proposed that the submission of an unavailability event with status “Unavailable”, $P_{max,available}$ = 0 and using the new parameter, avoids the change request process under specific conditions (total length of single unavailability, and total yearly occurrences of such event are time restricted) • For environmental limitations (ice, bird/bats) which would be anyway identified very close to real-time can be communicated as a Forced Outage, which do not require the System Operators validation.

4.7 Other design comments

Subject	Stakeholder	Feedback received	System Operators' view
Definitions	FEBEG	FEBEG questions the proposed definition of a Technical Facility (TF) and Delivery Point (DP), in particular the statement that "all wind turbines regardless of the asset owner are considered as one Technical Facility" (p. 15). The concept of being "operationally linked" should imply joint dispatchability or control, not just physical proximity. Separate SCADA systems or differentiated BRP responsibilities justify separate classification. The existence of different BRPs is a clear indication that assets cannot be considered as one TF under either operational or market arrangements.	There will be no review regarding the definition of Technical Facility, which determines the level at which Outage Planning Agent (OPA) obligations apply. However, clarifications will be provided in the design documentation and contractual agreements concerning the specification of Delivery Points. The contracts will set minimum requirements for the level of Technical Unit and Delivery Point. If more precise measurement is available and beneficial for the OPA, a more detailed subdivision of the Technical Facility may be permitted, provided this does not conflict with information requirements for other products (such as CRM, BRP, mFRR, FCR, etc.). However, for all Delivery Points associated with a single Technical Facility, different OPAs could be designated by the Grid User.
CDSO role	Febeliec	Febeliec would like to address explicitly the specific case of Closed Distribution Systems as well as Closed Distribution System Operators, which are for their underlying grid users the relevant system operators. It is important that their specific status is duly taken into account in the design of outage planning. Moreover, it is important that for the definitions on CDSs and CDSOs a formal reference is made to those definitions resulting from European, federal and regional legislation, in order to avoid incompatibilities and discrepancies with other regulatory or contractual frameworks and to avoid as much confusion as possible. Febeliec also wonders how DSO-connected CDSOs will be involved in the outage planning processes. Febeliec as always remains available to further discuss any of these issues based on its experience with CDSs and CDSOs.	In the contractual documents related to the extension of the OPA design to small units and demand facilities directly connected to the TSO grid, the correct legal references will be used when defining CDSOs and CDSs. It will be clearly stated that assets connected to the DSO grid via a CDSO are excluded from the next implementation phase of iCAROS. Within the T&C OPA applicable to assets connected to the TSO grid, it will be specifically indicated that the OPA responsibility remains with the relevant Grid User, even when the grid user is a CDSO. In such cases, the CDSO's role is to facilitate and ensure that each connected CDS User is aware of their obligation to appoint an OPA for their respective assets, supporting in this way the correct implementation of the process.

Information level	COGEN Vlaanderen	Given that: 1. CHP-installations need to be located near one or more Grid Users that consume the produced vectors (e.g. electricity, heat, CO_2) in order to be able to realise the primary energy savings through cogeneration; and 2. the expected evolution towards a multi-asset approach Grid Users could thus potentially optimise their own energy production and consumption "behind the meter", limiting their impact on the electricity grid, based on the different assets (production, storage, consumption) at their disposal. The current design note mentions that the OPA needs to provide its availability status and the corresponding maximum active power available at technical unit level (e.g. wind park, solar park, CHP, battery, offtake, etc.). However, it is unclear how the system operator will combine these different elements in its validation process and which profile will be assumed for each of these and other assets connected to the grid elements. Whereas a conservative calculation method could quickly result in a refusal or acceptance (potentially) subject to financial compensation, in reality this might not necessarily result in grid issues due to an optimisation by the Grid User "behind the meter".	The design proposed by the System Operators is tuned on most of the small production and storage units: the original design will be maintained. Information about the unavailability of a unit remains crucial for operational security analysis, even when the active power offtake at the access point is unaffected, as information at technical unit level will also provide crucial information for the assessment of the reactive power situation on that location. Additionally, a review is foreseen six months after the go-live to evaluate the need for further design adjustments.

5 Annexes

The non-confidential reactions received by the System Operators to the informal public consultations:

- 1. Aquiris
- 2. Bnewable

- 3. COGEN Vlaanderen
- 4. Edora
- 5. Febeg
- 6. Febeliec
- 7. Ventis SA
- 8. ODE