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Report

TDC Phase B – Final Report

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Glossary

Term	Description
ACER	European Union Agency for the Cooperation of Energy Regulators
Activation location	Location where flexibility is activated
AES	French abbreviation of the association of Swiss electricity companies ("Association des entreprises électriques suisses")
aFRR	Automatic Frequency Restoration Reserve
Baseline	A counterfactual reference about the power that would have been withdrawn or injected if there had been no flexibility activation.
Bid	Flexibility offer that is tailored to a specific product
BRP	Balance Responsible Party
CM	Congestion Management
CNE	Critical Network Elements: A network element that is strongly affected by flexibility activation and which is therefore modelled separately in the flow-based market clearing optimisation. The easiest way to define a CNE is as an interconnecting element between local market areas. However, if N-1 criteria apply, the concept can be expanded to Critical Network Elements and Contingencies (CNECs). See literature on flow-based market coupling for more details.
DER	Distributed Energy Resource. A generic term for technologies such as batteries, heat pumps or electric vehicle chargers. See also "TE".
DPS	Delivery Responsible Party Schedule
DSO	Distribution System Operator
ElCom	The Swiss National Regulatory Authority
EnG	German abbreviation for the Swiss federal act on energy ("Energiegesetz")
ENTSO-E	European Network of Transmission System Operators for Electricity
EnV	German abbreviation for the Swiss federal ordinance on energy ("Energieverordnung")
EU	European Union
EV	Electric vehicle
FCR	Frequency Containment Reserve
FSP	Flexibility Service Provider. FSPs can be both technical and commercial aggregators.
Flexible connection agreement	A connection agreement where a grid user's use of capacity for parts of the grid connection is not granted at all times
Highly local constraint	A grid constraint that is too local to be treated with local market area resolution, such as a single network level 6 transformer or network level 7 feeder
Interface node	Point at the property boundary between the grids of two DSOs or a DSO and the TSO
INS	Information Schedule
LApEl	French abbreviation for the Swiss federal act on electricity supply ("loi sur l'approvisionnement en électricité")
LEn	French abbreviation for the Swiss federal act on energy ("loi sur l'énergie")
LFS	Load Flow Sensitivity. The LFS is a number between -1 and 1 that quantifies how much the power flow across a network element (transformer / line) changes when the power injection at a node is modified. LFS = 0 means that there is no effect, whereas LFS = 1 means that any change in the nodal power injection leads to an equal change in the power flow across the network element.

	Negative signs are possible depending on the orientation of the network element (i.e. if the “from” and “to” nodes are reversed), and in meshed grids.
Mantelerlass	Joint revision of the Swiss federal acts on electricity supply and energy in 2024
mFRR	Manual Frequency Restoration Reserve
MURD	Model for the Use of Swiss Distribution Networks
MW(h)	Megawatt (hours)
NC DR	Network Code on Demand Response
Net position	A "net position" is the sum of all activated flexibilities in a market area, considering the sign (positive for injection increase, negative for injection decrease).
Net position limit	A net position limit is a constraint on the flexibility activation that can be allowed in 1 or several local market areas. The term “net position” is borrowed from power markets and refers to the net import or export of a market area.
NOVA	German abbreviation for the principle imposed on Swiss system operators to 1) optimise the grid before 2) reinforcing it before 3) expanding it by building new lines
OApEI	French abbreviation for the Swiss federal ordinance on electricity supply (“Ordonnance sur l’approvisionnement en électricité”)
OEne	French abbreviation for the Swiss federal ordinance on energy (“Ordonnance sur l’énergie”)
PPS	Production Responsible Party Schedule
Product	A (flexibility) product is a tradable unit of flexibility that is offered by an FSP, with attributes such as price, volume and delivery period. It is possible that a single product can be used for multiple services such as congestion management and control energy.
PV	Photovoltaic
Request location	Location where a SO requests flexibility activation to take effect. The request location for a service can consist of 1 or several local market areas or network elements that are known to the market platform (i.e. for which the SO has calculated LFSs). To deliver a service at a request location, the LFS between the activation location and the request location needs to be sufficiently high.
RPS	Reserve Responsible Party Schedule
Service	The term (flexibility) service is used to describe the purpose for which a SO procures flexibility, such as congestion management or control energy.
SFOE	Swiss Federal Office of Energy
SO	System Operator
SPG	Service Providing Group. A group of TEs and/or SPUs. The TEs in an SPG must fulfil prequalification criteria as a group, whereas individual TEs may not.
SPU	Service Providing Unit. A group of 1 or more TEs that are connected at the same grid connection point. If the ensemble of TEs in an SPU does not fulfil prequalification criteria, the SPU must be combined with other TEs/SPUs to form an SPG.
StromVG	Swiss federal act on electricity supply (“Stromversorgungsgesetz”)
StromVV	German abbreviation for the Swiss federal ordinance on electricity supply (“Stromversorgungsverordnung”)
Supplier	The entity which supplies or acquires electricity to/from the DERs
TDC	TSO-DSO Coordinator
TE	Technical Entity, a single DER which can be controlled individually and which cannot be further subdivided.
TSO	Transmission System Operator
VC	Voltage Control
VSE	German abbreviation of the association of Swiss electricity companies (“Verband Schweizerischer Elektrizitätsunternehmen”)
WACC	Weighted average cost of capital

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1 Introduction

The rapid emergence of distributed energy resources accentuates challenges at all grid voltage levels, from local grid constraints to system-wide power imbalances. However, flexible resources such as batteries, heat pumps and charging stations can provide valuable services to contribute to a stable and secure grid operation.

The TSO-DSO Coordination (TDC) project aims at establishing a coordination mechanism to enable flexible distributed energy resources (DERs) to provide grid and ancillary services in an efficient, scalable and grid-secure way.

TDC was launched in 2021 as a pilot project between ewz, Swissgrid and EQUIGY, where a relatively simple rule- and priority-based concept was developed and partially tested with the main data exchanges between the TSO, a DSO and a flexibility service provider (FSP), using the EQUIGY Crowd Balancing Platform.

In the subsequent TDC Phase B, AEM, Axpo, CKW, Groupe E, Primeo, Romande Energie and St. Galler Stadtwerke joined the project. In Phase B, the concept was refined and complemented by considerations for market and product design, potential business models to develop and operate the coordination mechanism, a legal and regulatory analysis and an approximate roadmap for implementation. This document summarises the main results of TDC Phase B, and is structured as follows:

- Section 2 introduces the scope of TDC in terms of flexibility services. Furthermore, since implementing the full coordination concept of TDC Phase B will entail significant developments for the TSO, DSOs and FSPs, possible simplifications are described for participating in TDC.
- Section 3 introduces the products designed to fulfil the services from section 2.
- Section 4 describes the developed coordination mechanism in the form of a user journey, outlining the main processes and data exchanges within TDC
- Section 5 introduces the TDC aggregation model and further market design considerations
- Section 6 summarizes the relevant legal and regulatory framework
- Section 7 contains considerations regarding the value added by TDC, and lists options for which entities could be responsible to develop and operate the central platform
- Section 8 concludes this report with an outlook towards future phases of TDC

2 TDC Phase B high-level requirements

This section summarises the requirements from Flexibility Service Providers (FSPs), Distribution System Operators (DSOs) and the Transmission System Operator (TSO) towards a coordinated, joint market for distributed flexibility, the hereafter called TSO-DSO Coordinator (TDC). As the requirements may vary significantly between different companies and will evolve over time, there is significant uncertainty about when the requirements become binding. As TDC will evolve correspondingly, the objective is to list the foreseeable requirements, but not necessarily consider all of them for the first implementation.

2.1 Flexibility service assessment

Table 1 summarises the flexibility service assessment for TDC, based on inspiration from The Universal Smart Energy Framework (USEF), which provides a classification of flexibility services described in USEF: The Framework Explained [1]. Services considered within TDC Phase B are marked in green.

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Table 1: Flexibility services assessment for TDC. Services considered within the TDC Phase B scope are highlighted in green.

USEF classification	Description Short description	Urgency When do we expect this service to become relevant/useful?	Relevance for TDC In scope for Phase B? Later?	Max. geographical resolution At which aggregation level can the service be provided?	Recurrence Once the service becomes relevant, how frequently is it needed?	Duration of single provision How long will the service need to be activated at a time (at most)
Balancing	FCR	Immediately useful	Later (should be considered in DSO grid constraints)	Control zone CH	Continuously	up to 15’
Balancing	aFRR	Immediately useful	Later (should be considered in DSO grid constraints)	Control zone CH	Continuously	15’ for voluntary bids
Balancing	Integrated Market (mFRR and international congestion management)	Immediately useful	In scope since Phase A	Control zone CH	Continuously	15’ for voluntary bids
Voltage & Congestion mgmt.	network level 6+7 voltage & congestion mgmt.	Immediately useful	In scope since Phase A	Local	Up to multiple times a day	Up to multiple (peak) hours
(Voltage &) Congestion mgmt.	(Voltage &) congestion mgmt. at medium and high voltage	Immediately useful	In scope for Phase B	Regional	Less frequent than network level 6+7	Up to multiple (peak) hours
Congestion mgmt.	TSO congestion mgmt.	Immediately useful	In scope for Phase B	TSO node	Up to ca. daily	Up to multiple hours
Grid capacity mgmt.	Network level 6+7 grid reinforcement deferral	Immediately useful	In scope for Phase B	Usually whole area with interconnected grid connection points to the upstream SO	Up to multiple times a day	1-2 hours at a time

USEF classification	Description Short description	Urgency When do we expect this service to become relevant/useful?	Relevance for TDC In scope for Phase B? Later?	Max. geographical resolution At which aggregation level can the service be provided?	Recurrence Once the service becomes relevant, how frequently is it needed?	Duration of single provision How long will the service need to be activated at a time (at most)
Grid capacity mgmt.	Equipment lifetime extension all grid levels	Not urgent	Later	-	-	-
Grid capacity mgmt.	Facilitate planned maintenance	Not urgent	Later	-	-	-
Grid capacity mgmt.	Reduce grid use fee payments	Immediately useful	In scope since Phase A (as peak management was in scope)	Whole area below interconnection transformer	Up to daily	1-2 hours at a time
Grid capacity mgmt.	Loss reduction	-	Later	-	-	-

The key difference between the services "congestion management" and "grid reinforcement deferral" as discussed here is predictability and probability of occurrence. On the one hand, congestion management is used to avoid violations that are hard to predict and do not occur very often. If on the other hand there are predictable, structural violations that are expected to occur often, there is a trade-off between whether to avoid them with grid reinforcement or by having a flexibility service that can be activated for this purpose.

If the flexibility resources are abundant, perhaps no separate reservation product is needed and the flexibility for such recurring violations can be procured together with the "congestion management" needs (with the risk of having not enough liquidity). Otherwise, indeed, long-term products procured in advance for the times with anticipated structural congestions would be needed. In any case, using flexibility against structural violations / congestions should be seen as a measure that allows to minimise grid reinforcement, but not necessarily to substitute reinforcements completely.

2.2 Requirements for DSOs and the TSO

To reduce the hurdle for DSOs and the TSO to participate, the required data and abilities should be kept as minimal as possible. A rough overview of the required data, processes and foreseen DSO/TSO participation possibilities is shown in Figure 1.

	Participation			
	passive	static	dynamic	maximum
Required data				
Live measurements	none		partial	state estimation
Grid model	none	topology		up-to-date, PF-ready
Forecasts (baselines, flow, voltage)	none	historical data	short-term, online	location-specific
Processes				
Calculations (power flow, clearing)	none	estimations	data-driven	(O)PF
Constraints (voltage, congestion)	"copperplate"	static limits	time series	with power flow
Own flexibility needs	none	based on hist. data		power flow/forecast

Figure 1: Overview of DSO and TSO participation possibilities.

While the columns in Figure 1 show four participation categories from "passive" to "maximum", each DSO/TSO does not have to fit within one unique column for all data and processes. Furthermore, the coordination concept developed in Phase B should enable the DSOs and TSO to start simple (passive/static) and evolve over time.

Sections 2.2.1 - 2.2.4 describe the main participation possibilities.

2.2.1 Passive participation

If a DSO does not have any flexibility needs and does not expect any grid constraint violation due to flexibility activation of third parties, there is no active participation needed.

In this case, the DSO is only required to approve the registration of new resources. In return, TDC can inform the DSO about third-party activations in its grid.

2.2.2 Static participation

In this case, the DSO/TSO performs offline grid studies at irregular intervals (e.g. once per year), analysing a few representative scenarios. If there are any expected grid constraint violations if all registered flexible resources were activated, the DSO/TSO can impose static limits on the activation. For example, the DSO/TSO could impose that the total activation in its grid never exceeds 1MW.

Furthermore, if there are regularly recurring flexibility needs, those can be defined offline and in advance. For example, a DSO could set an automatically recurring order on TDC to reduce the load every weekday during peak hours by 1MW if the price is X CHF/MWh or lower.

To ensure market efficiency, simplified participation levels must not be used to set conservative limitations, which reduce the liquidity to the detriment of TDC as a whole. Therefore, the market impact of limitations should be minimised, and limitations should be calculated according to transparent and verifiable criteria. Furthermore, if possible, the static participation level should be temporary on the way to more dynamic participation.

2.2.3 Dynamic participation

Rather than using static limits and automatically recurring orders as in Section 2.2.2, a DSO/TSO can use more recent data and some live measurements to create short-term forecasts and to calculate its own flexibility needs and activation limits more dynamically.

As the TDC mechanism is required to be agnostic to the DSO calculation method, data-driven calculations based on smart meters and measurements from transformer stations could be used.

2.2.4 Maximum participation

In this case, the DSO/TSO has full visibility of its grid in real-time, sophisticated forecasts and a grid model for online power flow simulations or optimisations. While these tools and data would make the procurement of flexibility and setting of limits very efficient, it may not be realistic nor necessary for all DSOs.

2.3 Requirements for FSPs

Unlike the DSO, the FSP is required to be a relatively active market participant without many derogation options. However, as shown in Figure 2, it is possible to share the tasks between a technical FSP and a commercial FSP. While the technical FSP (Section 2.3.1) faces the fleet of individual resources (abbreviated as TEs for “Technical Entities”), the commercial FSP (Section 2.3.2) takes care of interacting with the market, bidding with Service Providing Units (SPUs) and Service Providing Groups (SPGs) which allow TE aggregation.

→ Information flow

Required data / Processes	Role: Technical FSP	Flow	Role: Commercial FSP
Required data			
Structural technical data (e.g. max, min, prequalified power)	TE	→	SPU/G
Measurements (e.g. status, power, state of charge)	TE (ex-post possible)	→	SPU/G (live for ctrl energy)
Forecasts (available flex, baselines/schedules)	TE	→	SPU/G
Processes			
Acquire flexibility, register and prequalify TEs and SPU/Gs	TEs	→	SPU/Gs, prequalify
Determine available flex and (verify) baselines under uncertainty	TE (baselines), avl. flex	→	(SPU/G baselines)
Determine prices, provide initial bids and schedules incl. baseline	-		Bidding
Update bids/avl. flex/baselines (grid constraints, forecast errors)	TE (baselines), avl. flex	⇄	(SPU/G baselines), bids
Receive awarded bids and dispatch TEs	Send (& track) setpoints	←	Receive & disaggregate
Provide data (monitoring/transparency/settlement for SOs and BGs)	TEs	→	SPU/Gs
Manage use limitations and rebound effects	Provide info	⇄	Adapt schedules, dispatch

Figure 2: FSP participation possibilities.

2.3.1 Technical FSP

The technical FSP's responsibility is to manage individual TEs. Using structural technical data and recent or live measurements, the technical FSP forecasts the available flexibility. Depending on the coordination concept, the technical FSP is also required to forecast a baseline (i.e. the behaviour of the TE without flexibility activation) [1]. The TE-level available flexibility (and baseline) information is forwarded to the commercial FSP, who creates aggregations and bids for the market.

After market clearing, the technical FSP receives dispatch information from the commercial FSP, updates the TE setpoints accordingly and monitors the TEs. Monitoring data are also forwarded to the commercial FSP, who in turn may forward the data to DSOs/TSO and/or balance groups for settlement purposes [2].

The technical FSP is also required to manage use limitations, uncertainty in availability and rebound effects. Some TEs in its fleet may only be activated a few times per day/week/month, others may become unavailable unexpectedly. Furthermore, rebound effects may require the technical FSP to update the baselines of previously activated TEs. These challenges will be taken into account when designing the TDC market.

2.3.2 Commercial FSP

The commercial FSP receives TE-level information from the technical FSP and uses this information to create aggregations in SPUs and SPGs. SPUs are sets of 1 or more TEs connected to the same DSO grid connection point, which can fulfil a service. SPGs are sets of TEs connected to different DSO grid connection points, but which are not large enough to fulfil a service individually (e.g. they cannot achieve the minimum bid size individually).

[1] This topic has not been adressed in TDC Phase A.

[2] The current assumption is that a platform such as EQUIGY's Crowd Balancing Platform will take care of monitoring and settlement calculations.

The commercial FSP also performs all market-facing tasks, such as prequalifying SPU/Gs and creating, monitoring and updating bids. To determine appropriate prices, the commercial FSP also needs information about the cost of activating the TEs. This information is provided by the TE owner, either directly or via the technical FSP.

The commercial FSP manages use limitations, uncertainty in availability and rebound effects on the SPU/G level.

3 Product design

System operators face several system needs during planning and operational stages to stabilise the power system. The needs depend on the mandate of the respective SO and the voltage levels of their grid. For example, balancing is currently an obligation only for the TSO.

System needs can be addressed in different ways. One is the administrative way via the definition of requirements. A second way is via financial incentives such as dynamic tariffs. Another is the market-based way through the procurement of flexibility services by TSOs and DSOs. In the latter case, typically a set of specific flexibility services (e.g., frequency and non-frequency ancillary services) and well-defined products exist.

Two large groups of services can be identified, namely frequency control services that are location-independent, and non-frequency control services that are location-specific as shown in section 2.1. The novelty of product design within TDC is on the latter group of services, nonetheless both service groups are considered.

3.1 Flexibility services covered in TDC Phase B

This section summarises the flexibility services covered in TDC Phase B, from which the requirements for the TDC products are derived. Note that implicit (price-based) flexibility services that do not require explicit control by FSPs, DSOs or TSOs are out of scope for TDC. Nonetheless, implicit services such as dynamic tariffs can complement explicit services, especially for voltage control and congestion management to avoid incentives for Inc-Dec bidding (see Section 5.7).

In terms of explicit flexibility services, some constraint management services used by DSOs and TSOs for grid operation are considered (see Table 1 in section 2.1):

- Voltage control (VC) (active power) to maintain voltage within limits.
- Congestion management (CM) on different network levels (NL) to maintain flows on network elements below limits.
- Among the use cases for grid capacity management (with limited willingness to pay by the SO), the reduction of grid use fee payments by reducing the power exchanged with higher voltage grids during peak hours and grid reinforcement deferral are considered.
- Among the balancing services, only mFRR, which is activated by awarding individual bids, is considered.

To deliver the abovementioned services, it is considered that "mFRR and international Congestion Management" [2] can provide a basis for defining products for the DSO-level services. It should also be noted that the product requirements for the TSO-level services "mFRR and international Congestion Management", and "Congestion Management on NL 1" are well-established and it is not within the scope of TDC to propose amendments. The following services are out of scope of TDC Phase B: FCR, FFR, aFRR, Restoration Reserve, inertial response, black start and controlled islanding, long-term reservation.

For the services on DSO level, namely, Voltage Control & Congestion Management on NL6+7 and NL2-5, and reduction of grid use fee payments, specific products (requirements & attributes) for TDC are defined.

3.2 Products for TDC

Two products are proposed to be used in TDC. Both are suggested as an activation and reservation product and can cover multiple time steps:

1. Power in-/decrease
   a. Activation product
   b. Reservation product
2. Power limitation
   a. Activation product
   b. Reservation product

The main differences between the two product types are the aggregation level and the balancing responsibility. While these topics are described in more detail in sections 5.1 and 5.4, the key distinction regarding product design and the flexibility services that can be fulfilled with these products is that the power limitation product is always provided at a single grid connection point, whereas the power in-/decrease product, FSPs can aggregate multiple DER on a national, regional or local level, depending on the geographic distribution of their DER. The power limitation product can be used for services which require flexibility activation at a specific node, such as voltage control and congestion management on NL 6+7 or at medium voltage if there is a large customer that cannot provide a power in-/decrease bid instead (e.g. due to uncertainty as described in section 5.1). For all other services except grid reinforcement deferral, the power in-/decrease product is preferred, since it is compatible with existing markets and processes to maintain the system balance as described in section 5.4. Grid reinforcement deferral is enabled by the reservation products, which allow flexibility to be reserved with longer time horizons (e.g. more than 1 day ahead).

Power in-/decrease and power limitation products can also be provided simultaneously by the same DER, as shown in Figure 3.

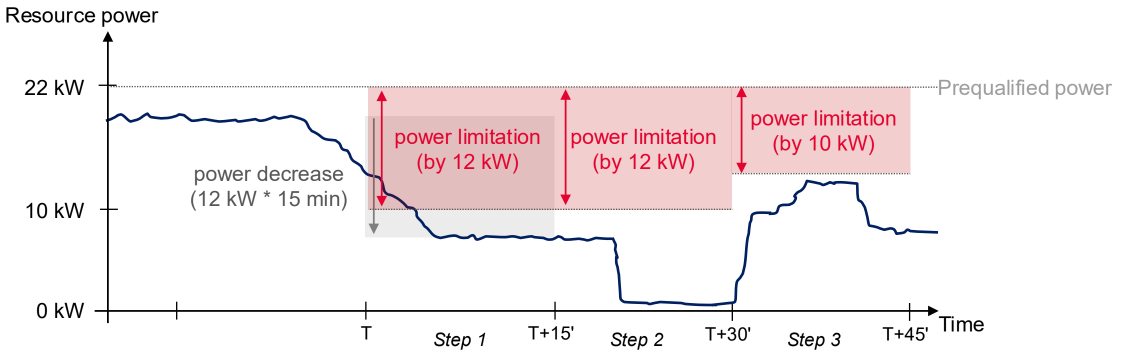

Figure 3: Example with power decrease (TDC product 1) and power limitation (TDC product 2) provided by the same DER.

With the possibility to procure flexibility over multiple time steps, the products cover the needed duration for services such as congestion management or reduction of grid use fee payments. In addition, the formulation of a multi-time-step demand over several time steps with not necessarily the same volume can be used to handle rebound effects. Figure 4 shows an example of a defined demand by a SO over several time steps with a reduced volume in the last time steps to cover rebound effects. Offers by FSPs are usually provided for each 15 minutes separately but can be combined as well if necessary.

Figure 4: Example of a multi-time-step demand by a SO and offers by FSPs

Reservation products are considered important to align with the current mFRR market and to ensure the liquidity in the TDC market. In TDC, an awarded reservation bid represents an obligation to place an activation bid with the corresponding volume in the activation market. Only “joint reservation products” are considered within TDC, i.e. a reservation bid can be procured by multiple SOs. This means that activation is independent from reservation and may be requested by any SO. The net position limits of all the SOs involved in a joint reservation bid are still respected in the activation clearing even if not all the involved SOs are participating.

3.2.1 Product 1: Power in-/decrease

3.2.1.1 Activation product

The attributes of the Power in-/decrease activation product are shown in Table 2

Table 2: Attributes of power in-/decrease activation product

Attribute	Unit	Specified in the SO request	Specified in the FSP offer	Value/Range
Power (Volume)	MW	Yes	Yes	
Granularity of Power	MW	Yes	Yes	
Min. quantity	MW	Yes	Yes	
Direction	-	Yes	Yes	
Price (activation)	€/MWh	Yes	Yes	Same range as mFRR, currently -15'000 €/MWh – 15'000 €/MWh in 0.01 €/MWh steps. Prices may be defined exogenously in some cases, see section 5.7.
Location	-	Yes	Yes	Market area according to the aggregation options described in section 5.1.
Baseline method	-	-	Yes	
Delivery period	-	Yes	Yes	One or several 15 minute intervals
Preparation period	min	-	Yes	2.5 min + n(15 min)

Ramping period	min	-	-	Fixed to 10 min from T-5' to T+5'
Gate closing	min	-	-	Fixed to ca. 25 min + n(15 min)
Accept all bids or none of group	-	Yes	Yes	
Accept only if no bid of mutually exclusive group is awarded	-	Yes	Yes	

With the attribute "accept all bids or none of group", multi-time-step bids can be defined. The attribute "accept only if no bid of mutually exclusive group is awarded" may be used when certain bids cannot be activated simultaneously, e. g. bids of the same DER in different directions.

The 10 min ramping period is consistent with mFRR and is designed to avoid peaks in FCR and aFRR every 15 minutes. Therefore, bids from continuously controllable and discretely switched DERs such as heat pumps should approximate a linear ramp as closely as possible. If ramping becomes an issue on national level due to too many discretely switched DERs, FSPs could be allowed to modify the “Ramping period” field in their bids, and the market operator could distribute the start of the bids’ ramping periods to approximate a linear ramp from T-5’ to T+5’ over all bids.

3.2.1.2 Reservation product

The attributes of the power in-/decrease reservation product are shown in Table 3.

Table 3: Attributes of power in-/decrease reservation product

Attribute	Unit	Speci-fied in the SO request	Speci-fied in the FSP offer	Value/Range
All attributes of product 1a, except "Price (activation)"				
Price (availability)	CHF/MWh	Yes	Yes	

3.2.2 Product 2: Power limitation

3.2.2.1 Activation product

The attributes of the power limitation activation product are shown in Table 4.

Table 4: Attributes of power limitation activation product

Attribute	Unit	Speci-fied in the SO request	Speci-fied in the FSP offer	Value/Range
Power limitation	MW	Yes	Yes	The amount of power by which the consumption or injection of a specific DER is reduced relative to the prequalified power of the DER. In case the maximum rated consumption/injection of the DER surpasses the rated limits at the grid connection point, the latter shall be used as reference for prequalification.
Granularity of power limitation	MW	Yes	Yes	
Min. quantity	MW	Yes	Yes	
Direction	-	Yes	Yes	
Price (activation)	CHF/MW	Yes	Yes	Prices may be defined exogenously in some cases, see section 5.7.
Location	-	Yes	Yes	Grid connection point according to the aggregation options described in section 5.1.
Delivery period	-	Yes	Yes	
Preparation period	min	-	Yes	2.5 min + n(15 min)
Ramping period	min	-	-	Fixed to 10 min form T-5' to T+5'

Gate closing	min	-	-	Fixed to ca. 25 min + n(15 min)
Accept all bids or none of group	-	Yes	Yes	
Accept only if no bid of mutually exclusive group is awarded	-	Yes	Yes	

The reasoning for the ramping period is the same as for the power in-/decrease product described in section 3.2.1.1.

3.2.2.2 Reservation product

The attributes of the power limitation activation product are shown in Table 5.

Table 5: Attributes of power limitation reservation product

Attribute	**Unit**	**Speci-fied in the SO request**	**Speci-fied in the FSP offer**	**Value/Range**
All attributes of product 2a, except "Price (activation)"				
Price (availability)	CHF/MW	Yes	Yes	

4 TDC Phase B user journey

4.1 Introduction

This section describes the coordination concept and processes developed in Phase B of the TDC project. The user journey, shown in Figure 5, takes into account the participation of four main groups of market actors the Flexibility Service Provider (FSP), which is responsible for offering flexibility and activating resources; the market operator, which manages the joint TSO-DSO market; the SOs (TSO and DSOs), which act as limit setters, buyers of flexibility services and guarantors of stability in the different network levels; and the suppliers and BRPs, who may receive information on the activation of flexibility planned (ex-ante) and completed (ex-post) by the TDC.

Schedules exchanged in the context of ancillary services today (PPS, RPS, DPS, INS – refer to glossary for disambiguation) are not specifically named in the user journey, as the interplay between TDC and existing scheduling processes is not yet defined. The aim is to integrate TDC as smoothly as possible while avoiding redundancies. The sections following Figure 5 will detail the processes and requirements with reference to the steps in the user journey.

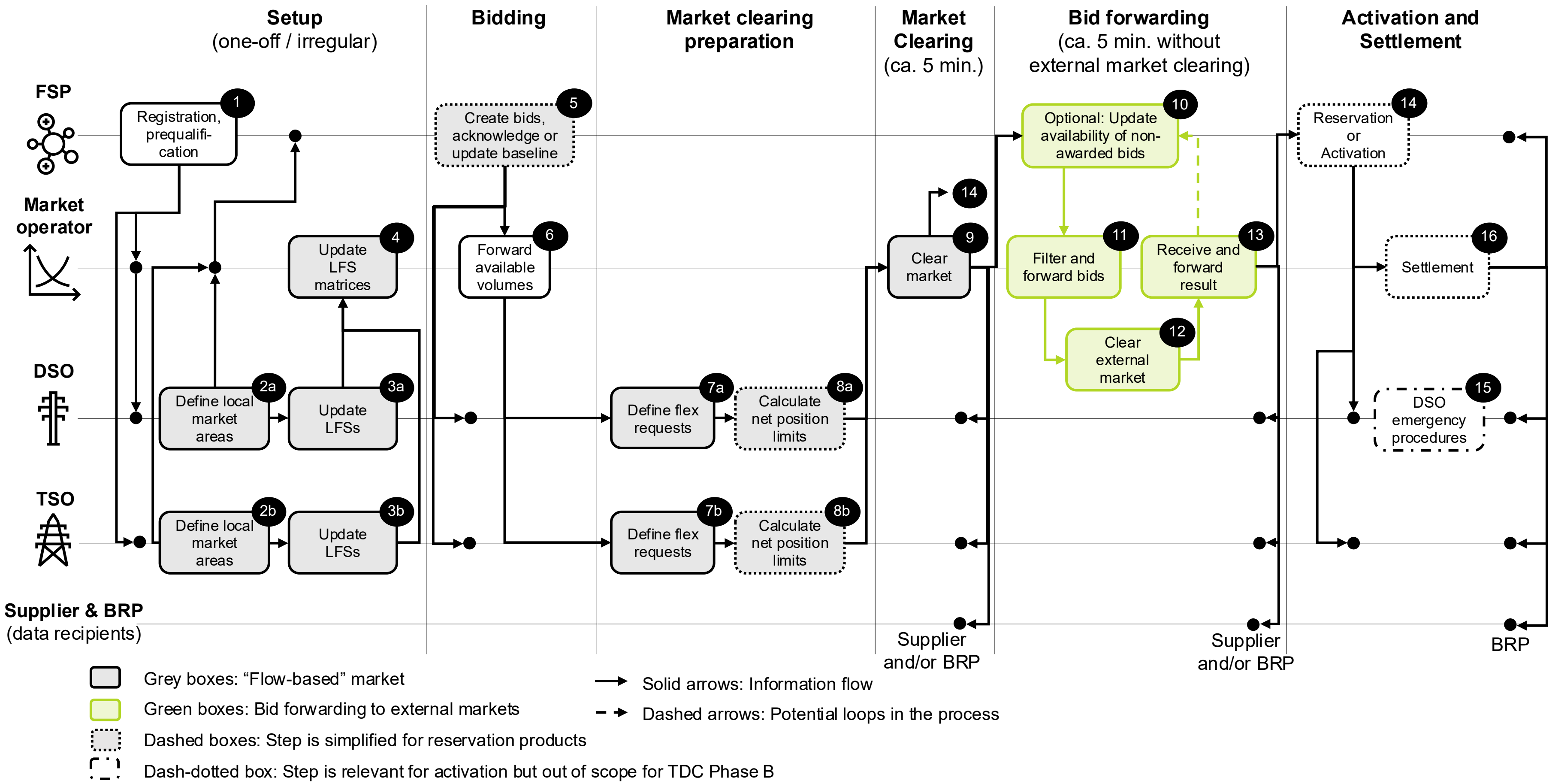

Figure 5: User journey of the TDC Phase B concept.

4.2 Setup steps

4.2.1 Registration, prequalification

The steps described in this section are not performed at every market clearing interval but are only necessary when onboarding a new DSO or when market areas or Load Flow Sensitivities (LFSs) need to be updated.

The initial eligibility check and the registration phase are carried out in Step 1 following the same principle described in TDC Phase A [3]. New Technical Entities (TEs) can be registered using a unique pseudonymised ID provided by FSPs and shared with the SOs and TE owners. IDs allow SOs to map TEs to a specific local market area (Step 2) and to a grid connection point (Steps 7 and 8). Each ID is also uniquely assigned to a supplier and a BRP.

The basic concept of TDC is based on local market areas, which are defined in Step 2 and are responsible for the geographical resolution of bids. The FSPs are generally charged to create power in-/decrease bids where all included SPU/SPG are within a single area. Local market areas are defined by the list of registered TEs assigned to them, the ID of the interface node with the lower voltage DSOs, and the list of neighbouring areas at the same or higher voltage levels. An example of local market areas is shown as blue outlines in Figure 6, whereas aggregation across multiple market areas is possible according to the TDC aggregation model (section 5.1)

As illustrated in Figure 5, the SO informs the market platform about the new market areas, and the market platform in turn informs the FSPs about which local market areas their TEs are located in and how they are connected to each other. Highly local constraints are addressed by the introduction of power limitation products, which have a DSO-nodal geographical resolution (section 3.2.2).

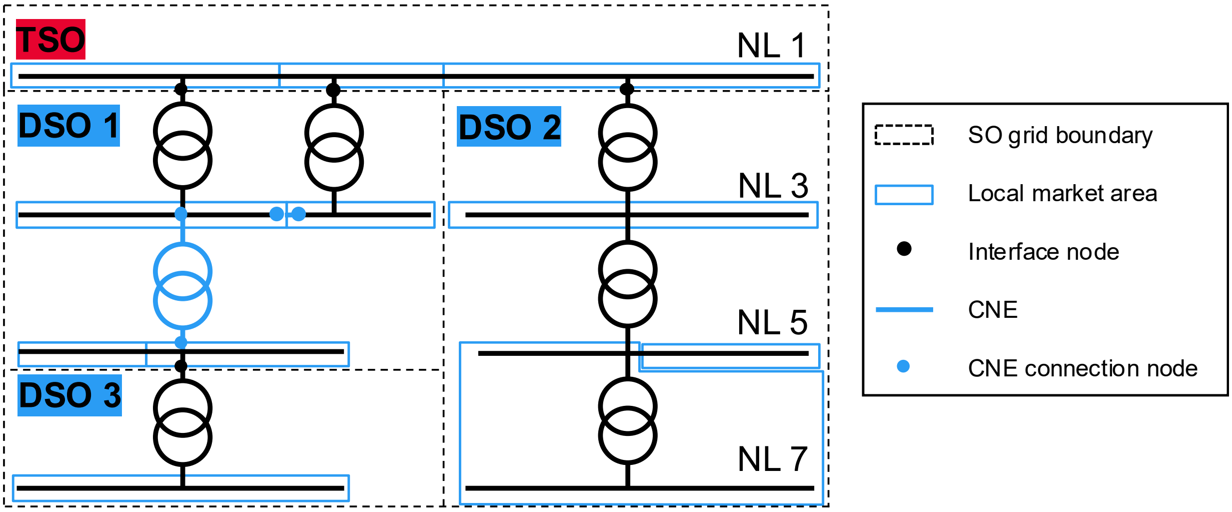

Figure 6: Illustration of local market areas and Critical Network Elements (CNEs).

4.2.2 Methods to define local market areas and update LFSs

The process to define multiple market areas is related to the data availability of the DSO and is carried out when onboarding a new DSO or if existing market areas should be updated due to new prevalent grid issues or significant topology changes. By changing the areas, it is also required to recalculate the LFSs (Step 3).

Several calculation possibilities can be envisaged, which consider a single local market area for the entire DSO or splitting the territory for purposes such as peak shaving or grid congestion management.

LFSs are defined as the sensitivity of flows across interface nodes or separately defined Critical Network Elements (CNEs) with respect to changes in the net position (=net active power injection) of local market areas [4, 5]. The calculation of LFSs typically require power flow simulations. However, if a DSO only has one local market area and is connected to the higher voltage grids at a single point, the LFS calculation can be omitted, as all injections in the DSO's grid influence the upstream grid with the same sensitivity. The same logic can be applied to DSOs with several local market areas and a single interface node, as long as the local market areas are connected in a radial structure.

If a DSO performs frequent switching actions that significantly alter the flows across interface nodes to other SOs, a separate set of LFSs should be calculated for each topological configuration to maintain a high accuracy. If an intermediate DSO in the cascade does not participate, the missing LFSs have to be estimated by the participating SOs.

While the LFSs described above are required for the market optimisation, SOs can voluntarily inform the central market platform about additional LFSs towards elements in their grid where grid constraint violations occur frequently (CNEs).

4.3 Bidding

4.3.1 Create bids, acknowledge or update baseline

In Step 5, the FSP provides information about the offered flexibility. Based on the DSOs' local market area definitions, the FSP submits bids for each local market area where they have prequalified SPUs/SPGs to the market operator. FSPs interested in aggregating flexibility across multiple local market areas are allowed to do so following the guidelines provided by the TDC aggregation model (section 5.1).

The TDC market incorporates bids for activation and reservation products, which were introduced and further detailed in section 3. Since the verification and settlement of reservation products do not require a baseline, the FSP creates, acknowledges or updates the baseline only for power in-/decrease activation products, which is used to verify the provision of the flexibility service and to account for energy exchanged between different balance groups. While the entity who initially provides the baseline may vary (e.g. FSP, an SO, the DER manufacturer or another party with access to the data required for forecasting), the FSP acknowledges or modifies the baseline in Step 5 and sends it to the market operator. The submission of baseline schedules is similar to the submission of the Production Responsible Party Schedule (PPS) and Reserve Responsible Party Schedule (RPS) that are currently used for control energy [6].

4.3.2 Forward total available volumes

After receiving the bid and baseline information from all FSPs in Step 6, the market operator forwards the information on baselines and the total bid quantities for all products for each local market area to the corresponding SO. SOs are also informed about the total power in-/decrease bids' quantities from local market areas in other grids which have nonzero LFS towards the SO's grid. Using this information, SOs can perform grid constraint checks, considering their own grid, but also influences of flex activation in the other grids.

4.4 Market clearing preparation

In Steps 7 and 8, the SOs determine their flexibility requests and constraints that will be considered when clearing the market. SOs have several possibilities to define their flexibility request according to their data availability, grid model details and simulation capability. Starting from a lack of flexibility needs (Option 1), SOs have the possibility to refine their flexibility request computing offline power flow simulations (Option 2), data driven simulations (Option 3) or forecasting & power flow simulations (Option 4), as described in section 2.2.

The flexibility request is generally declared at the local market area level and takes into consideration the LFSs between the local market area and the desired request location (interface node, CNE, or a whole local market area). However, for some specific cases at the DSO level, where highly local constraints are present, one or several grid connection points where TEs offer power limitation as a request location can be defined. Flexibility requests shall be submitted separately for power in-/decrease and power limitation products.

The SO is requested to calculate the maximum price it is willing to pay by estimating the consequences of not having the service delivered for all the cases with the only exception of congestion & voltage management with constraints that would lead to a critical situation if not resolved.

4.4.1 Define net position limits

The limits for flexibility activation in the different grid levels are computed in Step 8 by the SOs following the same data availabilities described in section 2.2 and receiving some additional data on the DERs from the central platform as described in section 4.3.2.

If one or several network elements are overloaded due to DER baseline and/or flexibility activation, DSOs can set upper and lower limits on set of nodes in their grids, by limiting additional flows across interface nodes, CNEs or the net flexibility in an individual local market area.

Since forecasting congestions or voltage issues becomes increasingly challenging with longer lead times (multiple days to weeks ahead), defining net position limits for reservation products will be more difficult than for activation products. Omitting net position limits for reservation products is a simple method and could be a starting point for TDC implementation.

4.5 Market clearing

By receiving as an input the FSP bids from Step 5, the SO flexibility requests and the net position limits from Step 7 and 8, the market operator clears the market in Step 9 by solving an optimisation problem similar to the algorithms described in [7, 8].

While implementation details of the market clearing will be addressed in future phases of TDC, a simple, sequential approach could be used, where highly local constraints are resolved first, followed by a market clearing optimisation for power in-/decrease products described in section 3.2.1. In any case, the market clearing algorithm only matches power in-/decrease requests with power in-/decrease bids, and power limitation requests with power limitation bids. Mutual exclusivity between power limitation bids in one direction and power in-/decrease bids from the same resources in the opposite direction are considered. Furthermore, the algorithm shall ensure compliance with net position limits for both a maximum power difference and or no power difference induced by the power limitation. The latter is the case when the operating point of the resource lies below the imposed limit. A maximum power difference would be the case when a resource is consuming maximum power and is then limited as offered in the power limitation bid.

Any bids that were accepted in this step are finally awarded. This means that these bids will be activated (or reserved for activation) in Step 14 and all the actors involved in the market are informed about the market clearing results. For transparency to all market participants (TSO, all DSOs, all FSPs and all BRPs), the awarded volume per local market area is published, potentially after a brief embargo period analogous to the control energy market results [9].

4.6 Bid forwarding

The bid forwarding process, which consists of four additional steps (Step 10-13), is introduced for bids that have not yet been awarded and for which the FSP has allowed the forwarding to external (e.g. international balancing) markets. Otherwise, if there are no markets available, the process jumps directly to Step 14.

Before being forwarded, bids may optionally be withdrawn and updated by the FSPs at Step 10. This step can be useful in case of significant forecasting errors of stochastically available DER flexibility. In Step 11 the market operator is responsible for filtering bids to ensure that all net position limits are respected by repeating the market clearing optimization. The external market is then cleared in Step 12, and the results with the awarded bids are sent back to the market operator in Step 13 which inform the FSPs and the other relevant on the reservation and activations.

The bid forwarding process can be repeated if there are further external markets to clear, starting from Step 10.

4.7 Activation and settlement

After receiving the information from the market operator that a bid was awarded, the FSP has the possibility to reserve or activate the flexibility depending on the type of auction. In case of reservation the FSP is obliged to place activation bids for the quantities reserved and needs to guarantee the availability of the resources during the reservation period. For control energy reservation, the FSP provides online monitoring data to prove its ability to deliver the volumes awarded. If an activation is requested, the FSP manages the corresponding resources to deliver the awarded bid at the activation location, and finally informs the market operator about the activation.

4.7.1 DSO emergency procedures

In case of events that cannot be forecasted (e.g. unexpected outages) which imminently endanger grid security in a given area, DSOs have the right to use flexibility in the affected area, even against the will of the TE owner, though any such emergencies must be proven and reported to the regulator. These actions can be performed at Step 15, where to use flexibility in emergencies, most DSOs are expected to roll out control mechanisms (e.g. via dry contacts in smart meters that can turn off DERs). Depending on the DSO and the type of emergency, DSO emergency procedures may be enacted at different geographical resolutions such as the entire DSO grid or the entire area connected to a transformer at any network level (2, 4 or 6).

Since such an intervention can lead to interruption of an ongoing activation, FSPs providing control energy can react if they notice that TEs in their portfolio are unexpectedly disconnected if cross-market area aggregation is possible or if they have power plants connected to the transmission grid as a backup. Otherwise, their balance group will face imbalance cost.

While the abovementioned processes happen completely outside of TDC, establishing TDC may open the possibility for more refined mechanisms that can involve the role of the market operator.

4.7.2 Settlement

By receiving as inputs the flexibility requests (Step 7), the net position limits (Step 8) and the LFSs (Step 4) used in the market clearing, the market operator initiates the settlement among the parties in Step 16. If a single bid benefits several SOs (e.g. reduces the peak load at multiple grid levels), the benefitting SOs share the costs as described in section 5.3.

Activation products are settled based on the delivery information from Step 14, whereas reservation products are remunerated if the FSP is able to keep the awarded volumes available, which can be verified using online monitoring data.

In accordance with current practice for control energy where FSPs receive the Information Schedule (INS) [6], the FSPs and BRP receive informational schedules that summarize and confirm all activations from their resource pools (for FSPs) and balance groups (for BRPs). Furthermore, the system operators are informed about the activated flexibility in their grid.

Billing may be handled through TDC, or by passing the settlement information to dedicated billing systems.

5 Market design

5.1 Aggregation model

According to the concept defined in the user journey in section 4, SOs define local market areas to procure flexibility according to their needs. As DSOs will increasingly face local congestion and voltage issues in their grids, market area sizes are expected to vary from medium to small. They may encompass an entire region, a municipality, a city district or even a low voltage grid section fed from a single transformer station. This can already be observed today on DSO long-term flexibility auction platforms such as Piclo Flex in Great Britain or Flexibilités Enedis in France.

From an FSP perspective, DER may be characterized as either deterministic or stochastic. An emergency generator for instance qualifies as a deterministic resource, as it is generally idle and - if not informed differently by its owner - available to provide power upon request by the FSP. An EV charging station on the other hand will consume electricity depending on its usage. Its operating point - and therefore the availability of its flexibility - depends on factors outside the influence of the FSP which are uncertain ahead of time. Similar uncertainties apply to the availability of flexibility of heat pumps or PV generation. These stochastic DERs make up the majority of DERs and are of particular relevance regarding congestion and voltage management in distribution grids. It is therefore crucial to address availability uncertainty in a flexibility market targeted at DER.

A common approach to deal with availability uncertainty in ancillary services markets today, is for FSPs to aggregate multiple flexible resources to provide a joint bid. Inside a group of many, stochastic fluctuations of single resources even out, the availability of the group can therefore be better forecasted. In the Swiss ancillary services markets, FSPs may aggregate resources across all of Switzerland.

For the power in-/decrease product of the TDC market, it is proposed to allow for multiple aggregation possibilities: FSPs may aggregate resources across a local market area for local bids, across multiple market areas at the regional level for regional bids, or across multiple market areas at the national level for national bids. While national bids may only be used for national services, regional bids may be used for both regional and national services, and local bids may be used for all three types of services, as shown in Figure 7. The advantage of this approach is offering FSPs a low entry barrier to the market as they may start participating with national bids while building up their local pools. Furthermore, it facilitates to attain minimum bid size with small resources.

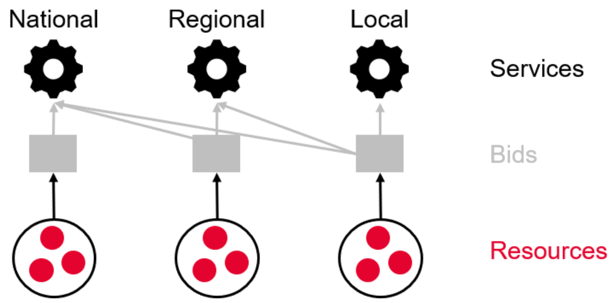

Figure 7: Aggregation model of the power in-/decrease product.

The power limitation product on the other hand is designed in a way that availability uncertainty does not pose a problem: power can always be limited regardless of the availability of the resource. Therefore, no aggregation is required for this product: a power limitation bid is formed by a single resource. Power limitation bids are intended to be used for local services towards DSOs such as highly local constraint management. To allow DSOs to also access flexibility of resources used for regional and national power in-/decrease bids, a resource may simultaneously contribute to a power in-/decrease bid and a power limitation bid. Compatibility of both types of bids is ensured by defining market rules such as mutual exclusivity of power limitation bids and power in-decrease bids in opposite power direction. The resulting aggregation model for the TDC market is shown in Figure 8.

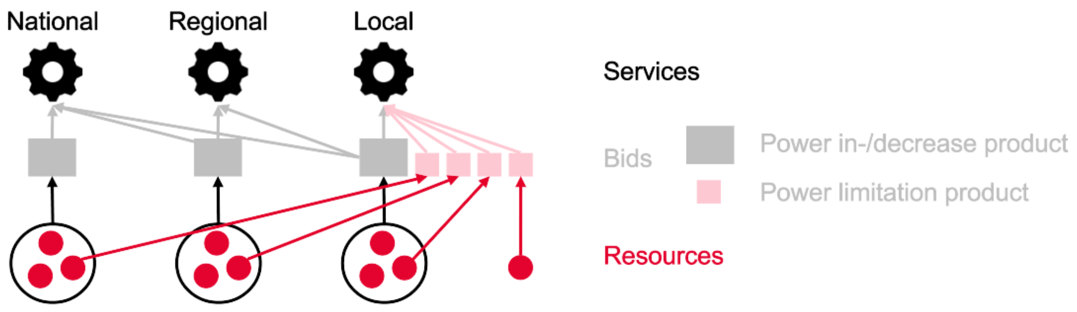

Figure 8: Aggregation model of the TDC market.

5.2 Timing and bid forwarding

The following market timing parameters are set for TDC:

- Maximum Full Activation Time (FAT), defined as the time between the activation request and the full delivery of the reserve: A maximum FAT of 12.5 min is set to be aligned with mFRR. This corresponds to a 2.5 min preparation period and a 10 min ramp (5 min before and 5 min after the start of the delivery period).

- Maximum Market Clearing Duration (MCD), defined as the time allowed to find the solution to the optimization problem of the market clearing: Maximum MCD is set to approximately 10 minutes. Calculation time depends on the complexity of the optimization problem, influenced by the number of market areas, time steps etc.

- Time horizon, defined as the set of consecutive delivery windows considered at market clearing: Time horizon is set to 1-4 hours based on SO needs and expected rebound effects. The achievable time horizon may be limited by the optimization problem complexity, and by the time for which FSPs and SOs are able to commit their bids and requests.

In addition to value stacking of the different products within the TDC market, the use of flexibility shall be maximized by forwarding bids not selected within TDC to external markets. Power in-/decrease bids could for example be forwarded to MARI (Manually Activated Reserves Initiative), a European market platform for manual frequency restoration reserves [3]. To enable bid forwarding, TDC and the external markets must be compatible in terms of product attributes, bid structures, market timing, pricing mechanisms, as well as technical and regulatory requirements. Discrepancies may be dealt with by processing TDC bids before forwarding, as shown in Figure 9. An example: If minimum bid size is smaller in TDC than in external markets, bids may be aggregated by the market operator before forwarding based on predefined rules or settings submitted by the FSPs.

[3] Switzerland is currently not connected to the central MARI platform.

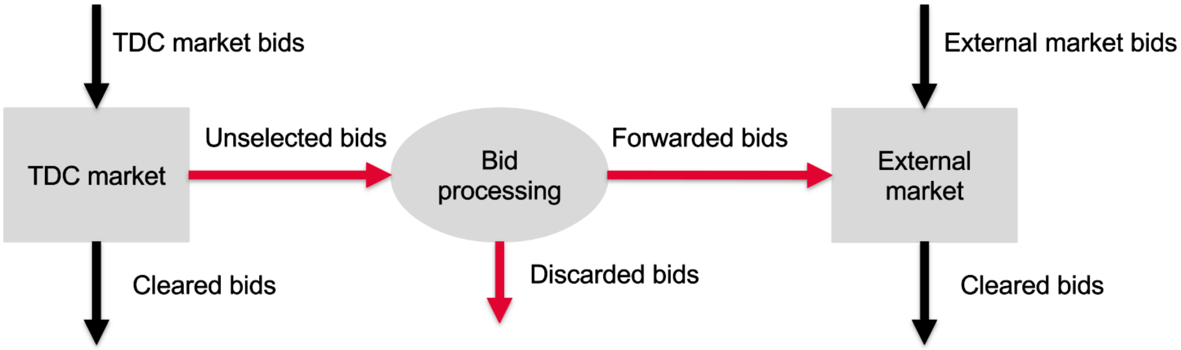

Figure 9: Bid forwarding concept.

5.3 Trading guidelines and pricing

Since local market areas are coupled, a single awarded bid can serve multiple SOs requesting flexibility in the same direction. The cost of activation is shared according to the following principles:

1. The activation of a bid is only remunerated once.

2. Each SO pays proportionally to the benefit that the SO derives from any local market area's activation. Specifically, the SO pays proportional to the load flow sensitivity (LFS) between the activation location and the request location of the SO's flexibility need, multiplied by the net position of the activation location necessary to fulfil the SO's request. Refer to the Glossary for the definition of activation and request location.

3. Extension of principle 2: A SO does not pay for flexibility activation that exceeds its needs, and an SO does not pay for any flexibility that counteracts their flexibility needs, except to balance its activations, if applicable.

Trading among FSPs can occur if FSPs bid in opposite directions with prices favourable for a trade. As TDC should not create a parallel energy market, this shall be prevented by introducing a corresponding constraint in the market clearing optimization.

As pricing scheme, both pay-as-cleared and pay-as-bid are possible. Pay-as-bid is favoured for new markets and applied in the Swiss control energy market at the time being.

5.4 Balancing

Positive and negative power in-/decrease activations are netted across the Swiss control area. To avoid a net imbalance, the market clearing optimization is extended by a constraint which enforces the net activation in the control area to be equal to the TSO's current control energy demand. Cost for any additional activations caused by this constraint is shared by the SOs contributing to the need. Post-scheduling processes as utilized today for tertiary control shall be applied to ensure that also balance groups do not face any imbalances due to power in-/decrease activations: The FSP's balance group takes over balancing responsibility for the FSP's activations with a corresponding energy transaction from the supplier's balance group.

Activations for the power limitation product shall however not be associated with an energy transaction, as the amount of energy shifted is uncertain ahead of time and problematic to determine in hindsight. If a resource is activated for both product types simultaneously, the balancing mechanism of the power in-

/decrease product takes effect. Only if the total power difference induced by power limitations exceeds that of an activated power in-/decrease bid, or if a resource is only used for power limitation, an alternative balancing mechanism is needed. It is proposed to assign balancing responsibility to the supplier's balance group, which is already accounting for the uncertainty of the operating point of the resource without TDC. A power limitation imposed by TDC, however, becomes certain at the time of market clearing. This information could be sent to the concerned suppliers and their balance groups for them to correct their position if needed. Attention needs to be paid to the timing: Should the TDC market clearing take place after day-ahead or even intraday spot market closure, the balance groups' ability to react may be limited. Whether this will pose difficulties depends on the amount of total energy shifted due to power limitations and how reliably this may be forecasted by suppliers and their balance groups. It shall be noted that the same challenge is faced by suppliers and their balance groups if a DSO directly activates flexibility outside of TDC, as is already possible today, with the difference that no information flow to suppliers and their balance groups is established. TDC would offer the benefit of introducing and standardizing the information flow.

An overview of balancing responsibility for flexibility activations for different products and market clearing times is shown in Figure 10.

For transparency reasons, balance groups shall generally be informed about flexibility activations for both the power in-/decrease and the power limitation product, excluding commercially sensitive information.

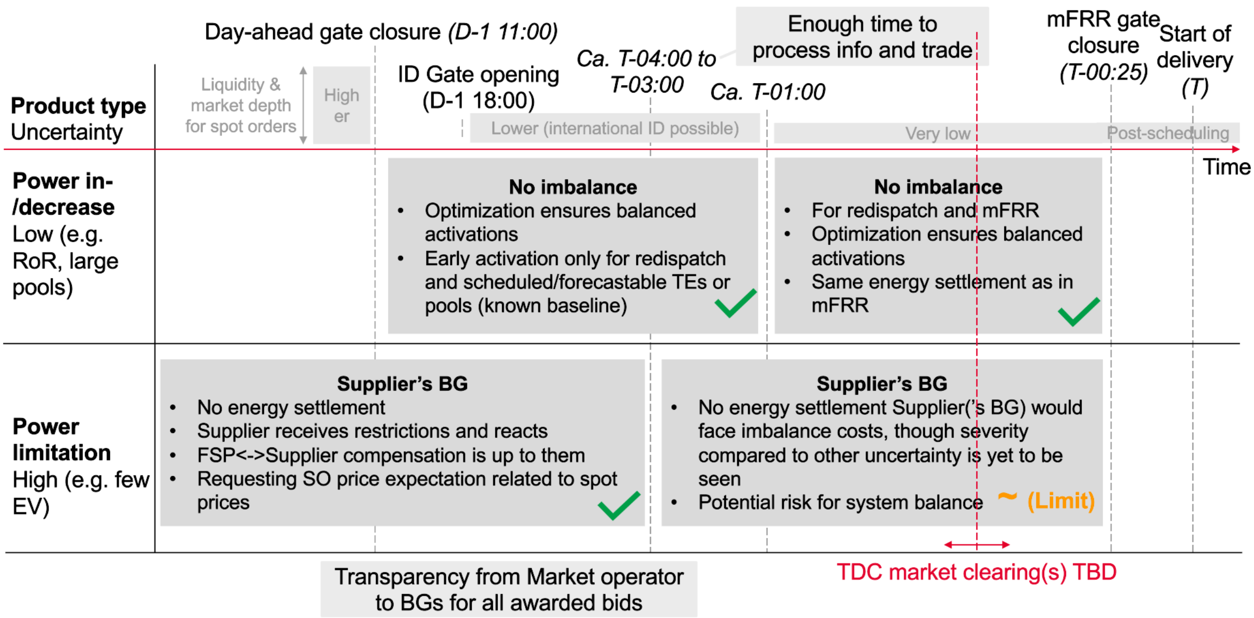

Figure 10: Balancing responsibility for flexibility activations for different products and market clearing times.

5.5 Baselining

Typically, in balancing markets, the delivery of the requested flexibility (product delivery) is verified by comparing the metered vs. the scheduled generation or consumption of the unit. However, in the case of distributed flexibility provision, verifying product delivery from a DER resource is a challenge because no individual power injection / withdrawal schedule exists. A proposed candidate solution to this challenge is the use of a "baseline", i.e. a clearly defined power exchange level, replacing the "scheduled exchange", against which the amount of delivered flexibility is measured.

Multiple methods exist to set baselines, some based on historical data, others based on real-time measurements. Alternatively, baselines may be self-reported in advance by FSPs. Ideally, the selected baseline method should accurately estimate the level of consumption or production of the resource without flexibility activation, while being simple to understand, implement and verify for all parties. At the same time, it shall ensure integrity, i.e. the method should be difficult to manipulate or "game".

To maintain a high attractiveness of the TDC market for the parties responsible for baselining, the use of baselines is reduced as much as possible. Baselines shall primarily be used for delivery verification of the power in-/decrease product, rather than for FSP and SO forecasts of the net position in a local market area prior to a flexibility activation. Furthermore, baselining shall take place at the most aggregated level possible, e.g. by verifying the delivery at the delivery location rather than for individual resources whenever possible. For delivery verification of the power limitation product, no baselines are needed.

5.6 Mechanisms for incomplete delivery

Establishing a well-defined settlement regulation is essential to encouraging the participation of all stakeholders and fostering the growth of the market. Such regulation must not only ensure an environment of mutual trust between buyers and sellers, but also pay attention to transparency and non-discrimination of the parties involved.

For the power in-/decrease product, it is proposed to build on the existing mechanisms of the tertiary control market: Activation is paid for independently of actual delivery. Should an FSP not deliver as activated, their balance group faces imbalance energy cost. Reservation is monitored through online monitoring signals; violations are penalized considering a 0.1% grace factor. Repeated violations may lead to the exclusion of the FSP from the market. The existing mechanisms shall be adapted to ensure delivery within the correct TDC market areas.

For power limitation products, a proportional payment could be applied. However, if power limitation products are needed to solve highly local constraints, the payment curve may need to be cut off sharply.

The introduction of penalties shall be avoided during the initial phase of TDC market deployment to reduce barriers for new participants. As participants gain experience in the flexibility markets, the introduction of penalties for incomplete delivery will be considered, still with the objective of not discriminating against the participation of smaller FSPs, while at the same time incentivising the provision of reliable services.

5.7 Challenges for local markets

Designing a concept based on local market areas entails a list of challenges for the proper functioning of a flexibility market:

1. **Market power**: Since local market areas are expected to be quite small, the volume of available flexibility and the number of FSPs per local market will likely be limited. If a single FSP controls most of the available flexibility in a local market area, the FSP may be able to dictate prices, available flexibility and to drive competitors out of the market. Potential measures to reduce the risk of market power being exercised include ex-ante & ex-post detection methods, the use of reference pricing, or lowering entry barriers for small FSPs.
2. **Discriminating, inefficient or intransparent procurement**: Due to limited available data and resources, some DSOs may join TDC with a more passive role and using simplified calculations. Such simplified, data-driven grid models and algorithms to request flexibility and limit activation entail a risk of discrimination of FSPs and reduced economic efficiency. The primary measure to mitigate this

challenge is to provide assistance to DSOs to enhance their calculations and participation level over time. Transparency may be improved by SOs providing qualitative information about grid limitations.

3. **FSPs forecasting SO flexibility needs:** Using historic and public data, FSPs can forecast the flexibility need of SOs to some extent. Therefore, a rational strategy for FSPs is to increase prices when they expect a larger share of the available flexibility to be needed. In extreme cases, FSPs can exacerbate expected congestions with uneconomic baseline behaviour, expecting a windfall income from the flexibility market (so-called Inc-Dec bidding [10]). A potential measure could be to perform ex-post analysis of market data to identify suspicious market behaviour and issue justification requests, warnings, or penalties to concerned FSPs. However, the extent to which price variations are justified cannot be defined easily. Another measure could be to only remunerate flexibility reservation while activation is not paid for or to remunerate activation based on a predefined mechanism. Further consideration of how to address this challenge is necessary in future project stages.

6 Legal and regulatory analysis

After developing the high-level requirements, the products, coordination process, and the market design for TDC Phase B in sections 2 to 5, respectively, the developed concepts and proposals were compared to the relevant legal and regulatory framework, focusing on:

1. The laws on electricity supply (LApEl in French / StromVG in German) and on energy (LEn / EnG). Both laws were revised and approved in a federal vote on 9. June 2024 in a package called “Mantelerlass” [11].

2. The ordinances of the electricity supply law (OApEl / StromVV) and of the energy law (OEne / EnV) which were revised in accordance with the Mantelerlass and consulted from 21. February to 28. May 2024 [12]

3. “Branche” documents under the jurisdiction of the association of Swiss electricity companies (AES in French / VSE in German)

4. The Network Code on Demand Response (NC DR) which is being drafted and established at the European level

Section 6.1 describes the findings of the analysis and stakeholder engagement with the Swiss Federal Office of Energy (SFOE), VSE and the regulator ElCom. Section 6.2 contains conclusions and an outlook for the legal and regulatory framework of TDC.

6.1 Analysis of the applicable legal and regulatory framework

This section is divided into an analysis of the current applicable framework, the Swiss *Mantelerlass* and a shorter outlook towards relevant Swiss *Branche documents* as well as EU regulation around the upcoming NC DR.

6.1.1 Current framework: Swiss Mantelerlass

Topic	Background and Core Team analysis	Stakeholders feedback and foreseen impact on TDC
Cost eligibility for TSO & DSOs investing in the TDC target solution	• Cost eligibility is a central factor for development and operation of the TDC coordination mechanism. • The costs for developing and operating ancillary service markets are already eligible for the TSO today. Article 15(2.d) of LApEl/StromVG and Article 19a(1) of OApEl/StromVV confirm that costs for procuring grid-serving flexibility is also eligible for DSOs.	• The consulted stakeholders agree that there appears to be no immediate blocking point for the TSO or DSOs to invest in and develop TDC. The importance of efficiency (to keep tariffs low) and of avoiding mixed investments between regulated and unregulated parties were highlighted
DSOs procuring flexibility through FSPs and from downstream DSO service area	• DSOs may use flexibility to serve the grid in their service area according to Art. 17c, paragraph 2 of the LApEl/StromVG. • Art. 19a paragraph 1 of OApEl/StromVV states that flexibility is deemed to be used for the benefit of the grid when the distribution system operator acts to relieve locally tense grid situations and to avoid, reduce or postpone economically inefficient grid expansion.	• None of the consulted stakeholders has expressed any reservations about the possibility for a DSO to acquire a flexibility service for its own local distribution network via an FSP, whether the latter has contracted the service within the DSO's service area or in a network downstream of its service area • Art. 17c paragraph 1 of the LApEl/StromVG introduces the principle of the flexibility owner's freedom to transfer his flexibility to a third party. Nothing prevents this third-party player from reselling this flexibility in the form of services to DSOs. • Reducing the monthly peak power drawn from the national grid is also to be considered a regulated use of flexibility. These costs should be eligible via TDC as well.

Competition and coordination between DSO-flex owner and SFP-flex owner contracts	• Flexibility owners can choose to sign a contract with and sell their flexibility to a DSO (according to OApEI/StromVV Art. 19b-c) or to an FSP (or third party). This creates a competitive situation for FSPs and DSOs to contract flexibility.	• From the consulted stakeholders' perspective, a competitive optimization of the flexibilities on the market is desired. TDC, as well dynamic network usage tariffs, are a step in this direction. • Each DSO can benefit from an opt-out clause for existing flexibility and is free to adapt its conditions to remain attractive
Flexible connection agreements	• Analysis of whether imposing of unilateral flexible connection agreements (on either new or existing connections) could be a compliant alternative for the DSO to avoid the complexity of flexibility uses.	• Under the current law, it is not possible to refuse or limit the end use of the connection permanently or repeatedly without a remuneration model, on which the end customer also agrees. If the customer wishes to pay for full power and does not accept an alternative proposal, the DSO is legally obliged to set the connection and pay its share of the costs.
Flexibility register	• With an increasing number of DERs, rises also the administrative demand for their accurate and up-to-date registration, so that the scheduling and settlement processes work correctly and transparently. • Inquiry about the development of a centralised database enabling the stakeholders to register flexible resources via a platform	• The consulted stakeholders see the advantage of such a database in opening up the flexibility market to the public, by offering transparency and user-friendliness • The development of a flexibility register as part of the Datahub project is legally possible, however a short-term establishment is not foreseen, since such a register is not listed in StromVV. • TDC considers such a flexibility register a key enabler for a liquid market and its correct settlement.

6.1.2 Outlook: Swiss Branche documents

The Core Team analyzed branch documents about flexibility. Two documents were examined in depth:

- Distribution Code Switzerland (DC-CH) [13]
- Model for the Use of Swiss Distribution Networks (MURD) [14]

The DC-CH addresses the subject of flexibility in chapter 5.10. This chapter describes load and injection management. It is not directly related to the project, but rather to the use cases specific to the DSOs.

Appendix 8 of the MURD addresses intelligent control and regulation systems for grid operation. This appendix outlines the opportunities and constraints of this system.

The analysis of the documents did not reveal any contradictions with the TDC project.

6.1.3 Outlook: EU framework & the new Network Code Demand Response

In parallel to TDC Phase B, a new European Network Code on Demand Response (NC DR) is being developed. Since the content of NC DR will not be finalized until 2025, and the applicability of NC DR in Switzerland is not yet clear due to the missing electricity agreement, the following chapter does not contain a detailed analysis, but rather a short summary of key topics with high relevance for TDC. The summary is based on the network code draft that EU DSO Entity and ENTSO-E submitted to the European Union Agency for the Cooperation of Energy Regulators (ACER) on 8. May 2024 [15].

Topic	Description of NC content	Foreseen impact on TDC
Aggregation models	• Terms and conditions for service providers that aggregate controllable units, specifying methods for calculating energy transfer, imbalance correction, and financial transfers. • Each Member State shall implement at least one aggregation model and ACER shall monitor and report on these models.	• The general guidelines set by NC DR for the aggregation models are compatible with TDC and seem to follow similar considerations
Baselining	• General principle: ENTSO-E and the EU DSO entity are required to maintain and update a register of approved baselining methods. A common assessment of these methods is mandated.	• Baselining methods of TDC Phase B go along the same direction. The final methods should consider the latest technological developments and should

	• Specifications and validation processes for baselining methods, responsibilities of system operators in validating the delivered services and requirements for data collection frequencies and standards compliance are detailed • Periodic re-evaluation of the baselining requirements • Grants stakeholders access to relevant customer data for validation purposes	be compatible with the approved baselining methods in ENTSO-E and EU DSO Entity's register.
Settlement	• Settlement principles • Responsibilities for calculating and settling activated local services • Requirements for data exchange to settle local services • Imbalance settlement for local services	• Nodal information and grid limitations should be considered accordingly to the already mature settlement, data exchange and imbalance processes applied by the Swiss TSO on the ancillary services market, ensuring compliance of the TDC market with the NC DR
Flexibility register	• Flexibility registers shall be established at national level which record the information for registration, prequalification, and verification of FSPs, SPUs and SPGs	• The requirements in NC DR for flexibility registers match the need for correct and up-to-date assignment of DERs to their suppliers and balance groups, as identified in the TDC Phase B market design (sections 4.2.1 and 5.1). Such a data platform in Switzerland would be essential for a liquid TDC market.
Procurement of flexibility for local services	• System operators shall choose the most efficient and effective solutions to address congestion and voltage issues through active power • The procurement for local services should generally be market-based, unless the national regulatory authority permits rule-based mechanisms after an assessment of both options. • Local service markets shall be coordinated with other electricity markets, such as day-ahead, intraday and balancing markets.	• Market-based procurement matches the principle of competition for DER flexibility foreseen by the Swiss stakeholders (see section 6.1.1). • TDC adds to the possible revenue streams for DER flexibility, together with other compatible markets.

Local market operators	• Role of local market operator specified • Relevant national regulatory authority ensures oversight of the local market operator(s) • Options on how local market operators should be appointed	• The role of the local market operator as outlined in the NC DR is similar to the one laid out in the TDC User Journey (see section 4). • Both business model options discussed within TDC foresee a single entity responsible for operating the TDC market (see Figure 11), thus matching the second drafting option in NC DR more closely than the first. However, if any Swiss DSO decides to design and operate their own local market outside of TDC, an interface to TDC could be offered to enable bid forwarding to TSO-level platforms.
Product design	• EU, ENTSO-E and EU DSO Entity shall develop and maintain a common attribute list which shall be used as a basis for the congestion management and voltage control products at national level. • National regulatory authority can allow the use of additional attributes.	• Although the common attribute list is not yet defined, the fact that the TDC power in-/decrease product is modelled on balancing products should ensure conformity. For power limitation products, the main issue to be clarified will be the imbalance adjustment described in section 5.4
TSO-DSO and DSO-DSO coordination	• DSO observability areas within which DSOs are entitled to receive structural, forecast and, where necessary, real-time information about grid elements and system user installations • Each system operator is responsible for forecasting and identifying congestion and voltage issues in its grid, using digital tools and data obtained from its own grid or through data exchanges with other DSOs, the TSO, service providers and system users	• The main principles of TSO-DSO and DSO-DSO coordination in NC DR are well aligned with the high-level requirements for TDC and the TDC user journey in sections 2 and 4, respectively. • While DSO observability areas are not explicitly foreseen in the TDC Phase B user journey (section

• Enabling of a grid prequalification process to be introduced at national level, where connecting and affected system operators can limit the flexibility provision of SPUs and SPGs or parts of SPGs if full activation of the SPU/G would exceed operational limits. In that case, flexibility provision can be limited for specific times, quantities and directions set by the system operator • DSOs can impose temporary limits in market processes for balancing and local services • System balance shall be ensured by solving imbalances due to local service activation as soon as possible with an effective and efficient solution that avoids activation of unnecessary balancing energy	4), they might help DSOs in their tasks and calculations. • A grid prequalification process is not explicitly foreseen in the TDC Phase B user journey (section 4) which does not focus on prequalification, but could be an additional possibility (in addition to predefined net position limits on local market areas) for simplified DSO participation as described in the TDC Phase B high-level requirements (section 2.2.2). • Requirement on temporary limits is met by the net position limits in the TDC Phase B user journey (section 4). • The balancing responsibility described in the TDC Phase B market and product design (section 5.4) mirrors these requirements.

6.2 Conclusions from the regulatory analysis and outlook

Both the Swiss and European legal and regulatory framework are generally conducive to TDC, without any fundamental barriers. However, the following topics will still require attention in the future:

1. **Implementation speed of the flexibility register**: An operational, up-to-date flexibility register is a key enabler for a liquid and well-functioning TDC market. Considering the rapid development of DERs, a national implementation should be higher prioritized, in order to keep pace with a timely launch of TDC.

2. The **Network Code Demand Response** is not yet final, and the Implementing Regulation (which will define operational procedures for demand response in retail electricity markets and which still needs to be drafted) may impose more requirements on TDC. The topic of **imbalance adjustments** in particular may influence the feasibility of power limitation products. Even though NC DR is not binding in Switzerland for the time being, the developments should be followed and compatibility ensured.

3. While the TSO and FSPs already participate in flexibility markets today, the TDC-related **processes and best practices for DSOs** are yet to be established. In that context, best practices could be gathered from the DSOs who participate in TDC at the initial rollout and published as a handbook by VSE.

7 Business model

This section describes the business model considerations made in TDC Phase B, which were based on the high-level requirements from section 2, the coordination process described in section 4, and the market and product design described in section 5 and section 3, respectively. The considerations outlined here are informed by the legal and regulatory analysis described in section 6.

7.1 Assumptions and clarifications

When elaborating the business model options for TDC, assumptions and clarifications were made for the following topics.

7.1.1 Targeted coordination mechanism

The TDC Phase B user journey in section 4 and market and product design in, respectively, sections 5 and 3 define a **common platform or common solution with TSO & DSO products and co-optimization** as a target. The business model options described in Section 7.2 are defined for this target solution. Business models are not analysed for potential intermediate steps on the implementation roadmap.

7.1.2 Development and operation

The business model options described in section 7.2 distinguish between development and operation.

- **Development** includes both the initial steps that establish the TDC platform / solution, and any further developments once the TDC is up and running.
- **Operation** refers to carrying out the tasks assigned to the market operator in the user journey from section 4, and operating the TDC platform/solution.

7.1.3 Regulated vs. non-regulated business

During the legal and regulatory analysis and stakeholder consultation described in section 6, the following clarifications were made regarding regulated versus non-regulated business:

- When **developing** TDC, the main question concerns cost recovery, i.e. whether regulated entities such as the TSO or DSOs can or cannot co-invest in the common platform alongside non-regulated entities. Since a non-regulated business would not be compatible with the current cost+ regime imposed on TSO and DSOs a co-investment between TSO, DSOs and FSPs is unlikely.
- Procurement of flexibility for ancillary and grid services is within the legal mandate of the DSOs and TSO and is therefore a regulated activity.
- The distinction of regulated vs. non-regulated business when **operating** the TDC platform/solution concerns cost recovery by the market operator. To be consistent with the development, it is assumed that whoever operates the common TDC platform/solution, will also be under a cost+ regime, such as for example the Regional Coordination Centres (RCCs) at EU level.

7.1.4 Governance and market monitoring

Regarding questions of decision-making and supervision of TDC, governance and market monitoring are distinguished.

- Within this document, **governance** refers to the act or process of making decisions about the TDC platform/solution: The decision-making and implementation of any decisions related to the TDC platform/solution in all phases (development, testing, operation, …) is covered under a governance regime, with the following two dimensions:

  - **Internal** dimension: This dimension addresses who is responsible and accountable for a decision related to TDC, how decisions related to TDC are made, and how new parties can join TDC.
  - **External** dimension: This dimension addresses how external stakeholders are involved in the decision-making process, e.g. with information or consultation. For those that are consulted, the governance regime will define a consultation process and way to integrate the stakeholders' views, where relevant.

- **Market monitoring** is a separate task in the supervision of TDC, which ensures that TDC operates efficiently, non-discriminatorily and according to the rules set for the TDC market. Considering the current regulatory regime and ongoing developments of the legal framework such as the introduction of a Swiss law on the supervision and transparency of wholesale energy markets, ElCom will act as the supervisory entity and recipient of market monitoring reports, whereas the operator of the TDC platform/solution will be required to monitor and flag any potential breach of market rules.

7.2 Business model options and assessment

This section is structured as follows. Section 7.2.1 describes the value of TDC for the roles described in the user journey in section 4. Section 7.2.2 provides an overview with a decision tree. The individual options for development are described in sections 7.2.3 – 7.2.4, followed by a conclusion and outlook in section 7.3.

7.2.1 Value of TDC

The TDC target solution aims to establish a flexibility market based on coordination among TSOs, DSOs and FSPs and offering various benefits over the uncoordinated status quo. Among the benefits of the TDC market are enhanced grid security and the optimized use of flexibility for both grid and system needs, promoting technical and economic efficiency of grids operation. The non-financial and financial value propositions by role (TSO and DSOs, FSPs) of TDC are shown in Table 6.

Table 6: Financial and non-financial value proposition of TDC for the TSO and DSOs, FSPs and market operator.

	Non-financial value of TDC	Financial value of TDC
DSOs & TSO	• Market-based access flexibility in other DSOs' grids • Access flexibility of FSPs in DSO's own grid • Access an organized marketplace (low fragmentation, price reference)	• Savings compared to grid expansion (NOVA) • Access to the technically and financially optimal flexibility • Cost sharing with other SOs • TSO: More liquidity in the balancing markets • Regulated business: No profits, but expected tariff reductions
FSPs	• Access an organized marketplace (low fragmentation, price reference), while addressing local DSOs' concerns • Gaining access to DSOs as new buyers	• Monetize the value of flexibility • Value stacking within TDC and through bid forwarding • Non-regulated business: Market needs to be attractive (prices, requirements, entry hurdles)
Market operator	• Reputation gain and business diversification	• Additional revenue stream • Operates as a Cost+ business: WACC-based cost recovery for running the TDC systems

7.2.2 Overview of business model options

The business model options discussed in TDC Phase B are shown below as a decision tree in Figure 11. For the **development** phase, the following questions led to a distinction of three potential options:

- Should the investment and ownership of the TDC platform/solution be within the regulated business?
- Does the TSO finance and own the initial development of the TDC platform/solution alone?

The preferred answer for the first question was “Yes” based on the considerations described in section 7.1.3, resulting in the exclusion of option 3. Options 1 and 2 for the development were further detailed and evaluated, as described in sections 7.2.3 – 7.2.4.

For the **operational** phase, two variations are possible. Since TDC is yet to be developed, the TDC Phase B partners focused more on development than on operation.

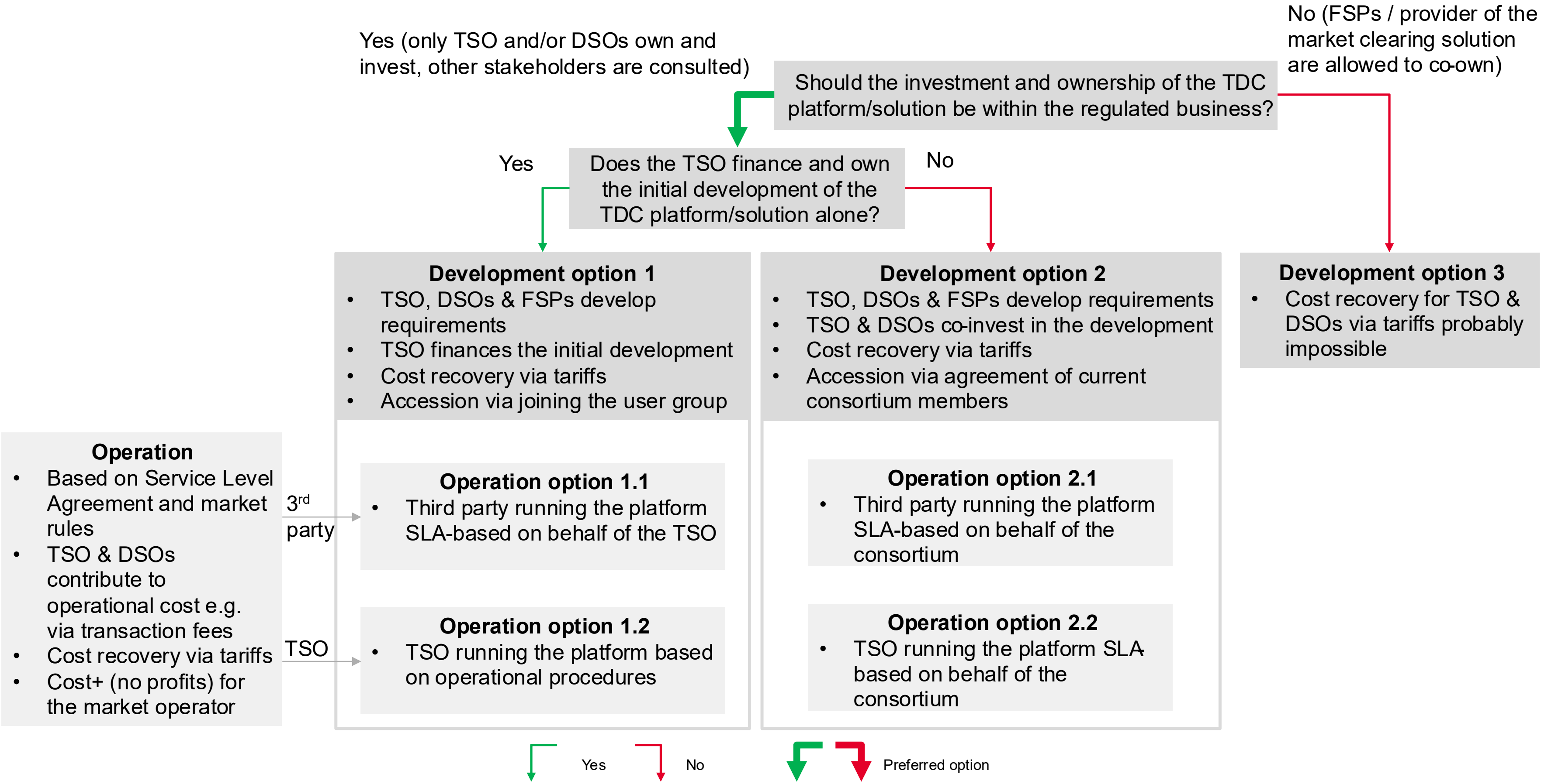

Figure 11: TDC business model decision tree.

7.2.3 Development option 1: TSO finances and owns the solution

This option is inspired by the current Swiss ancillary services markets, where the TSO is responsible for the development and finances the systems and resources necessary to operate it.

DSOs and FSPs are consulted on any developments through a User Group, in which requirements are gathered, proposals are discussed, and a consensus is sought. In the current ancillary services markets, the user group consists of all prequalified Balancing Service Providers. For TDC, an equivalent group including all DSOs and FSPs participating in TDC is organised by the TSO. New DSOs and FSPs can join the User Group as part of the process of joining TDC during recurring accession windows; be it during the initial development phase as prospective users, or as active participants in the market once TDC is operational.

Since the TSO finances TDC alone in this case, the cost recovery for the common platform/solution is done through the TSO tariffs.

7.2.4 Development option 2: TSO and DSOs finance and own the solution

In this option, the common solution is developed, financed and owned by the TSO and the interested DSOs through a cooperation agreement. The extension of the cooperation to further DSOs is possible for those DSOs who would join in a later stage with a due consideration of investment cost sharing. Further developments of the common solution are decided according to the governance principle of the cooperation agreement. The decision making duly considers the consultation of the different stakeholders via a dedicated User Group.

Since the TSO and the interested DSOs finance the common solution, the cost recovery for the common platform/solution is done through the TSO and concerned DSOs tariffs.

7.3 Conclusions on the business model and outlook

The business model options for development were discussed and assessed among the TDC Phase B core team, resulting in the following conclusions:

- Development option 1 with the TSO financing, owning and being responsible to develop the TDC platform / solution eases the implementation, reduces decision making complexity and leads to an even distribution of costs through the TSO tariffs. On the other hand, development option 1 requires consistent and transparent communication and consultation to build trust and a high participation in the User Group and the market.

- Development option 2 with a consortium of TSO + DSOs financing, owning and being responsible for development offers a more direct participation to a subset of DSOs, but is also more complicated in terms of governance and implementation, and leads to an uneven distribution of costs since the end consumers of the co-investing DSOs pay for TDC through both TSO and DSO tariffs. However, if there are DSOs who co-invest, this would be a tangible positive signal for the attractiveness of the market.

The business model options were designed for the targeted coordination mechanism while there may be intermediate steps in the implementation. Since intermediate steps in the solution may also require evolving business models, TDC Phase B was concluded without making a final recommendation. This topic will be re-addressed in future phases of TDC.

8 TDC roadmap

Introducing the entire TDC user journey from section 4 and all products from section 3 is a significant step forward for all involved parties. While the results of TDC Phase B describe the targeted state, TDC will be implemented step-wise. A High-level roadmap for the future phases of TDC is shown in Figure 12:

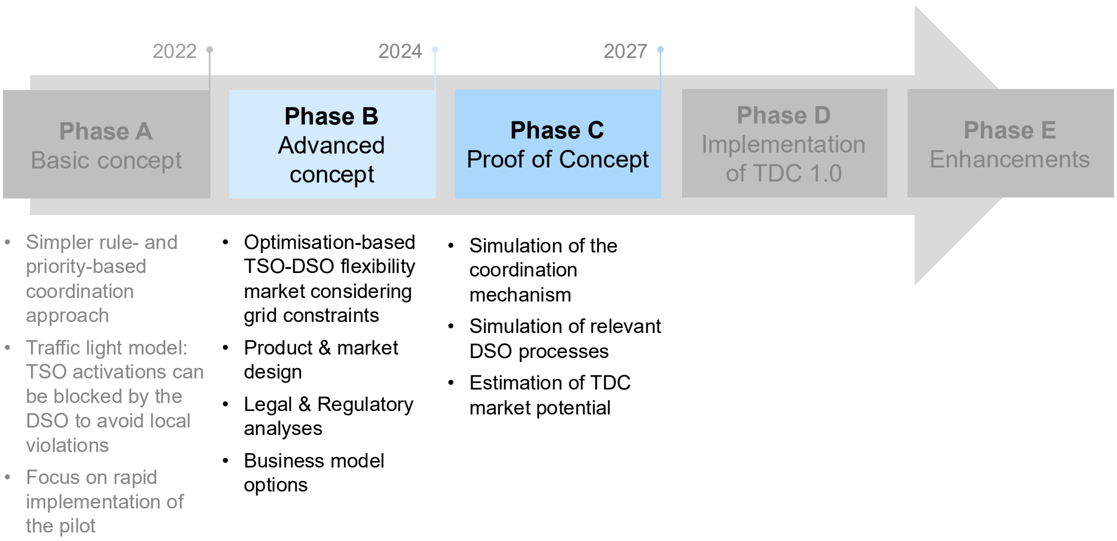

Figure 12: TDC high-level roadmap.

The upcoming Phase C is described in section 8.1 below. The exact scope and schedule for Phase D will be defined based on the insights gained in Phase D.

8.1 Scope and goals of TDC Phase C

While TDC Phase B achieved its goals of defining a scalable TSO-DSO coordination concept with product and market design guidelines, there are still open questions regarding the concept and the readiness of TDC to be implemented productively. Therefore, Phase C aims at:

1. Demonstrating that the market mechanism works, allowing both DSOs and the TSO to procure flexibility without leading to issues in the other SOs grids

2. Estimating the potential of TDC (as a whole, but also its individual products & processes) for FSPs, DSOs & TSO

To achieve these goals, a simulation, market potential survey and study, and a pilot are foreseen:

- The **simulation** will entail implementing and extensively testing a prototype of the optimization algorithm and TDC products with fictitious data.

- The **market potential survey** will raise awareness about TDC among DSOs & FSPs, get their feedback and assess the perceived potential of TDC. The following **study** will estimate plausible scenarios for the market size (MW(h) offered & requested)

- The **pilot** demonstrates the DSO processes in practice using measurements and data from 1-2 real DSO grids and real DERs, focusing on the novel features of TDC Phase B for DSOs (local market areas, sensitivities, activations).

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