Subject:	Elia consultation with regard to the design notes on the coordination of assets for system operations and market procedures (iCAROS)
Date:	15 January 2018
Contact:	Nicolas Leroy (EDORA), Steven Harlem (FEBEG) or Alice Detollenaere (ODE)
Mail:	nleroy@edora.be, steven.harlem@febeg.be or alice.detollenaere@ode.be

This document is a joint position paper of EDORA, FEBEG and ODE ('EFO').

Introduction

On the 11th of December, 2017 Elia launched a consultation with regard to the design notes on the coordination of assets for system operations and market procedures (iCAROS).

On its website Elia published the **following documents**:

- Future roles and responsibilities for the delivery of ancillary services;
- Design note for the coordination of assets: Part I – Outage Planning;
- Design note for the coordination of assets: Part II – Scheduling and Redispatching;
- Design note for the coordination of assets: Part III – Congestion Risk Indicator.

Elia also explicitly mentions that the scope of the design notes is limited to the assets connected on the Elia grid and to Elia-connected CDS and that the inclusion of assets connected to DSO grids is subject to a separate trajectory between ELIA and Synergrid and will be communicated at a later time.

Elia invited all stakeholders to give feedback on the design notes by the 15th of January, 2018. **'EFO' would like to thank Elia for its efforts in involving the stakeholders in the development of the design notes** as well for creating this opportunity for all stakeholders to express their comments and suggestions.

This document contains the evaluation, comments and suggestions of 'EFO': they can be considered as **non-confidential**.

Disclaimer

'EFO' would like to congratulate Elia with the **impressive work**. Notwithstanding the complexity, the diversity of topics and the interdependencies the design notes provide a very clear overview and image of what is actually being proposed. The examples help to understand the matter. 'EFO' also appreciates the effort of Elia to further define and describe – on request of the stakeholders – the roles and responsibilities.

By nature design notes are rather high level providing an overview and describing principles**. As the devil is in the details the comments and suggestions of 'EFO' cannot be interpreted as an approval of the proposals for coordination of assets for system operators and market procedures**.

Decisions on certain aspects, detailed implementation proposals and descriptions in the regulatory documents can still influence the final position of 'EFO'. **Especially the following aspects are still unclear**:

- ***Scope of the project***

  The actual range of assets that will be impacted by iCAROS is still not clear as the scope still needs to be defined. In that respect, 'EFO' would like to remind that the **proposed categorization of PGM's and demand facilities is only a working hypothesis**. Elia has already organized a consultation on the categories of significant grid users, but it has been decided to not already formally approve the proposed categories to allow adjustments to the initial proposal as a result of – amongst others – discussions within the framework of iCAROS.
  As a consequence, the comments and suggestions of 'EFO' shouldn't in anyway be interpreted as an implicit approval of the working hypothesis of categorization of PGM's and demand facilities. **To the contrary, based on the discussion on iCAROS 'EFO' considers it wise to reopen the discussion on some of the proposed categories**, e.g. limit A/B on 1 MW instead of on 0,250 MW.

- ***Missing links***

  Elia explicitly mentions that the scope of the design notes is limited to the assets connected on the Elia grid and to Elia-connected CDS and that the **inclusion of assets connected to DSO grids** is subject to a separate trajectory between ELIA and Synergrid and will be communicated at a later time.
  In the design note 'Future roles and responsibilities for the delivery of ancillary services' it is also stated that the **roles 'Voltage Service Provider', 'Defense Service Provider' and 'Restoration Service Provider**' still need to be defined and developed. The design of these roles will be part of projects starting in 2018.
  'EFO' understands that – seeing the complexity and the magnitude of the iCAROS project – certain aspects still need to be developed, but is **afraid that this could lead to a less coherent and efficient implementation**. Therefore, 'EFO' urges Elia to address the missing links as soon as possible in order to allow a coordinated implementation of all aspects of the iCAROS project.
  In the meantime the design notes should remain open for review to allow modifications to ensure consistency and level playing field when integrating the missing links.

- ***Link with flexible access***

  Elia announced to have the intention to integrate a framework for **flexible access in the federal grid code**. The details of the rights and obligations of all parties as well as the modalities still need to be discussed and agreed upon. In this respect, 'EFO' considers it important to

harmonize – also among TSO and DSO's - the mechanisms and procedures to provide the signal to lower the output of a generation facility.
In certain circumstances this flexible access will be limited, e.g. in volume or in time. Elia will have to compensate the grid user if it wants to use flexibility beyond these limits. 'EFO' is convinced that a mechanism with a financial compensation will never be able to correctly compensate all involved parties – grid user and BRP – and to fully neutralize the impact of the flexibility activation on market functioning. Therefore, 'EFO' urges Elia **to use the mechanism of redispatch – with correction of the BRP perimeter – to neutralize the impact of an activation of flexible access** whenever such compensation is obligatory. The use of the redispatch mechanism for the compensation of flexible access is not foreseen yet.

- ***Implementation timing***

Given the scope and the magnitude of the iCAROS project - and more generally the whole network code implementation process - the **targeted implementation date, i.e. April 2019, is considered as too strict to allow for a smooth and efficient implementation**.
Such large project requires a clear and joint long term planning to allow all involved stakeholders to reserve and schedule the necessary IT and development experts. Therefore, 'EFO' **welcomes the announced iCAROS implementation project**, starting in 2018 that will determine - in close collaboration with all the impacted stakeholders – an appropriate planning and transition period. Based on first assessments, 'EFO' is of the opinion that this transition and implementation period should **at least cover 3 years**.

- ***Regulatory documents***

The lack of a clear view on the organization of the regulatory documents is also creating uncertainty. Which principles will be in the federal grid code? Which ones in Rules, General Framework Agreements and Terms & Conditions? At the moment CIPU is a non-regulated contract while the abovementioned Rules and Terms & Conditions would be regulated. **As a consequence a trade-off needs to be made between flexibility to integrate modifications and stability of the basic principles.** 'EFO' is of the opinion that it should be clearly motivated why certain elements will become regulated and others not. 'EFO' asks Elia to be transparent on – and to consult upon - the future regulatory framework.
Although the detailed description of the roles and responsibilities is welcomed, 'EFO' wants to point out that the **actual regulatory documents (definitions, wording, liabilities, …) will be determining** for a final assessment of the proposals and a final positioning.

- ***Risk of over-regulation***

'EFO' fears that – as explained above - the scope of the iCAROS project will be too broad. As a result, Elia will trigger high IT implementation costs. **The benefits of these developments are only limited for market participants, while they will see the highest implementation costs**.
In 'EFO''s opinion **Elia should be a market facilitator:** Elia should rely as much as possible on market functioning – no evolution towards a central dispatching system - and should not

unnecessarily cause development costs or create reporting obligations without benefit for the grid users.

Positive evolutions

'EFO' acknowledges several positive evolutions in the proposals of iCAROS that are highly welcomed and supported:

- First of all, **'EFO' fully supports the objective to create a level playing** between all types of units/grid users and welcomes that efforts are made to remove all distinctions – and potential discriminations – between the former CIPU and non-CIPU, generation and demand, types of BSP's, … Nevertheless, 'EFO' feels **that Elia didn't succeed yet in creating a full level playing field between generation and demand** (see further).

- **'EFO' also appreciates the removal of the 'red zones' and the freedom of dispatch for all grid users**. This is considered as an important first step towards a fair and market-based congestion management mechanism. 'EFO' hopes that further steps can be made in the future, e.g. integration G-flex, evolution of the cost plus approach towards – as the liquidity in the market evolves – more free pricing elements, compensation for bids that are skipped, …

- 'EFO' also welcomes the **consistency between the day-ahead and the intraday schedule** as this will increase the coherency of the available data and improve the representation of the physical reality.

Main comments and suggestions

Level playing field between generation and demand

'EFO' regrets that - despite the efforts of creating one framework aiming at opening the market towards different actors and introducing technology neutrality – it still has to conclude that **there are different obligations for generation and demand**. The inconsistencies that exist nowadays are maintained or worsened; the only difference is that they are now explicitly described in the design notes.

The European guidelines are aiming at a much deeper integration of the market. It is disappointing to see that Elia is favoring and exempting demand from all obligations at every opportunity that arises. If the purpose of the iCAROS proposal is to secure the grid within the future energy landscape by obliging all flexible participants to provide all of their flexibility, **it should be applicable to all market participants in the same manner**, especially as demand is becoming an increasingly important element to manage the grid. The future operational procedures and IT tools of Elia, should be able to assess and cope with energy limitations.

Elia argues that it is not the core business of demand facilities to deliver flexibility services. Although this might be true, one would still expect for demand facilities voluntary wanting to enter the flexibility market to have to comply with the same rules to ensure a level playing field. In this respect, 'EFO' proposes Elia to apply the **same reasoning for category B units or to reconsider the limit between category A and B as managing the output of a solar installation or small CHP is often not the core business of the grid user either**. More in general, the specific situation of the prosumer – having to comply with rules for both demand and generation – deserves more weight in the documents.

Evolution towards explicit bidding

The shift from an implicit to an explicit bidding methodology will, in combination with the obligation to offer all available flexibility, have **a severe impact on the functioning of the BRP as this will limit the possibilities for the BRP to use his own capacity to balance his portfolio in real-time**. Suppose the BRP wants to balance his portfolio in real-time with the new rules. To be able to activate his own capacity the BRP will be obliged to first ask to his Scheduling Agent to send in a new schedule: as from the scheduling deadline until real-time he is thus obliged to use the imbalance market, which does not necessarily represent the cheapest unit at that time.

'EFO' is convinced that it is in the interest of all concerned parties **to be able to efficiently offer the required flexibility to the TSO** for grid security reasons. In this perspective, the proposals have some downsides. It moves away from the efficient implicit biddings for congestion and balancing purposes of large coordinable units towards complex explicit biddings for a large group of units. On top of that the provided explicit bids need to be firm: this implies one cannot longer freely re-nominate R2 between units like now without updating bids and schedules. The new rules will thus increase complexity and workload for market parties possibly impacting efficiency in offering flexibility to the TSO.

Finally, 'EFO' does not understand how **the obligation to firmly bid in all available capacity could be combined with the responsibility of the BRP to be able to have all means available to balance its perimeter** (e.g. offshore wind parks).

Balance between TSO and PGM as regards risks and costs

'EFO' has the impression that the **relationship between the TSO and mainly the PGM is not balanced with regard to redispatch, must run and may not run remuneration**. Flexibility is remunerated at cost leading to a loss of opportunity for the PGM, while the TSO has even opportunities to revoke the remuneration at any moment. The proposed remuneration is not in any way related to the risk the PGM bears in case of under-delivery, which will be penalized much higher than any possible incurred damages for the TSO.

Complexity will limit societal benefit

'EFO' is also not confident that the large scope and introduced complexity will trigger the overall anticipated societal benefit. The proposed changes will trigger **high IT implementation costs – for the TSO as well as for the market participants - without clear benefits for market participants**.

Obliging market participants to submit all available capacity as from category B - for both coordinable and low coordinable units- as firm explicit bids, will require a platform that can manages huge complexity and a vast amount of data. On top of that, the interaction between the balancing and the congestion bids will need to be managed on that platform which will require a large amount of data to be continuously exchanged between the TSO and the grid user.

Detailed comments and suggestions

General comments and suggestions

- If the current limit for the categories A/B remains, high costs will be triggered for small assets making investment in such assets less attractive in Belgium.
- With regard to balancing and re-dispatching bids, Elia argues that both have to be done explicitly, but for category B assets it is only mandatory for re-dispatching. How is the proposal for ON/OFF schedule for category B assets to be interpreted in this context? Why could one not keep the implicit bidding for category B assets, and especially the low coordinable units.
- By outsourcing the current activities performed by the ARP towards new roles and/or the grid users, 'EFO' observes that complexity is increasing significantly. This complexity combined with the increased responsibilities of the grid user – i.e. coordinating data exchanges between the various roles, remaining liable for the transmitted information and ensuring compliance to the regulation, … – could lead to the adverse effect that grid users no longer invest in on site decentralized generation or select different parties for the various roles. 'EFO' therefore propose to Elia to reconsider and simplify the scope of the project or to provide a framework for the grid users which they can use to fulfill this coordinating role, e.g. as done for the implementation of Transfer of Energy. Such a framework will also strengthen the confidence of other actors to make full usage of the proposed market design.
- Given the increased responsibilities of the grid users, 'EFO' would like to know when Elia foresees to inform the grid users of their new responsibilities and liabilities.
- On the definition of 'energy storage devices': why are all assets connected above 110 kV seen as type D? This is a stricter definition compared to the one for PGMs.
- Schedules for batteries in day ahead are unable to foresee the ancillary activation in intraday strongly impacting the 'the state of charge management'. It will be difficult to accept or offer (re-)dispatching bids for this reason. Are storage schedules compensated or a 15 minutes basis or not? If not, it could be simplification to have one schedule with + and – values, rather than two schedules.
- In case the BSP is using the 'transfer of energy', how can the grid user perform his coordinating role between grid user, scheduling agent and BRP while at the same time respecting the confidentiality requirements regarding the 'transfer of energy'?

Future roles and responsibilities for the delivery of ancillary services

- 'EFO' would like a clarification of who is in a contractual relationship with whom: if it is the grid user who stays responsible and liable, will there then be a direct contract between Elia and the outage planner/scheduling agent/...?
- Page 43-44: The responsibility of the grid user will significantly increase as consistency between the BRP-nominations and the schedules need to be ensured as the BRP will have to have the means to ensure consistency/balance.
- Elia mentions the new Federal Grid code will enter into force by the end of 2018, however according to the System Operations Guideline the deadline is set at 4/2019.

Part I – Outage Planning

- Page 14: 'EFO' supports the note on consistency with ENTSO-e and ACER requirements: it is of utmost importance to limit data flows for the same purpose and to guarantee overall consistency between data
  However, when faced with an outage, the information on this generation unit will need to be communicated to Elia on the same moment by 2 roles and for two different purposes: scheduling and outage planning. In addition, 'EFO' is wondering who will be responsible to publish this information with regard to REMIT: the BRP, scheduling agent or outage agent?
- Page 15-16: It is good that the 'testing' status is introduced. However it is not clear why it's not possible for a PGM to set the testing status after the 'Available' status (e.g. for tuning of regulating engine, R2 testing,…) while this is possible for demand facilities. Couldn't the same reasoning for demand facilities be used for PGM?
- Page 16: 'A request by Elia to reschedule the testing status before a mutual agreement is reached will not be remunerated' How is this sentence to be interpreted? If a unit is starting up after a revision (for which the end date was already long agreed upon) and therefore it has a 'testing' status, does Elia in this situation need to agree on this status? If Elia has not yet agreed, can Elia request to start the unit on a different moment?
- Page 21, footnote 18: Why do PGM's need to communicate without delay, while for demand that can be done in occasional meetings? Doesn't this demonstrate the lack of level playing, i.e. having the same requirements for participants in the same market?
- Page 22: The data exchange granularity on daily level should be aligned with the transparency obligations (DD/MM/YYYY hh:mm).
- Page 26, on demonstrable remuneration costs: It should be possible to provide an estimation based on past experiences and to only provide the proof when the request is confirmed.
- Page 26, §2: If an amendment annuls a previously requested amendment, it is not acceptable that the previous remuneration should be paid back.
  If there is for example 6 months between the two amendments, it is very likely that costs will need to be made twice (e.g. changing schedule with subcontractor, …)
- Page 26, §3, comment related to 'testing' status: It is not clear how Elia can ask to reschedule a testing status which occurs for a PGM after an 'unavailability status'; it would make sense if it is after an 'Availability' status.

Part II – Scheduling and Redispatching

- 'EFO' is of the opinion that it should be possible to schedule all PGM/PU in the same format in day ahead and intraday, and therefore avoid differences as seen today.
- Redispatching at cost is only possible if free dispatching is allowed in that sense that reacting to further impeding market opportunities and optimizing reserves are still possible.
- If balancing bids will be deactivated when a congestion bid is activated, 'EFO' would like to point out that this rule will also be applicable in case of a 'must-run' or 'partial may not run'. 'EFO' would like to specify that it will need to be clarified how a 'partial may not run' will effect the bidding obligations.
- Page 11, footnote 15 on delegation: the grid user may delegate the scheduling obligation by giving access to a data platform for schedules and bids but needs to remain responsible for settlement and liabilities. 'EFO' would like to understand what settlement is applicable here and why the scheduling agent may not perform this task as well?
- Page 12, on the sentence 'Elia will not accept incoherent levels for data exchange'. 'EFO' would like to point out that the iCAROS project is creating a more complex communication framework with several levels for data exchange (e.g. balancing on perimeter level, nomination based on access point, scheduling based on connection point, certain ancillary services per delivery point). This increased complexity – on top of that managed by different roles which need to be

coordinated - will require a very transparent and updated view on what Elia considers as coherent.

- Page 13, §2: Elia is making many efforts to facilitate the explicit biddings and scheduling obligations, e.g. by sending the updated schedule after an activations, or by putting balancing bids unavailable after activation of a redispatch bid.
  In this paragraph 'Elia will penalize the BSP in case of unavailability of the flexibility when Elia revokes the May-Not-Run'. 'EFO' would expect Elia to accommodate this and to warn the BSP in advance that the 'may-not-run' has been revoked so balancing bids can be restored.
- Page 14: It appears unfair to block the scheduling agent from providing information based on an inconsistency which is out of his role of control. If so, there should be time foreseen for the coordinating role to clarify the inconsistency. Secondly, it should be possible to clearly isolate the inconsistencies and allow the scheduling of any other assets for which there are scheduling obligations.
- Page 16, second example: How does the BRP guarantee consistency with the different schedules in this example? How can the grid user guarantee this? It will not be transparent what Elia will use for the demand forecast, nor will any consistency be guaranteed. Consistency could only be guaranteed by the grid user if there would equally be a scheduling obligation on demand.
- Page 17, on the sentence 'Elia may exempt …': Does this mean that the exemption is not confirmed yet, or that the exemption is not applicable on all PGM's?
- Page 18 and 19, demand: It is a missed opportunity to develop one framework for both demand and production. The European guidelines enforce by default the same obligation to demand as to production, and Elia makes a full exemption.
  Elia argues that it is not the core business of demand facilities to deliver flexibility services. Although this might be true, one would still expect for demand facilities voluntary wanting to enter the flexibility market to have to comply with the same rules to ensure a level playing field.
  In this respect, 'EFO' proposes Elia to apply the same reasoning for category B units or to reconsider the limit between category A and B as managing the output of a solar installation or small CHP is often not the core business of the grid user either.
  More in general, 'EFO' is of the opinion that the situation of the prosumers deserves more attention. 'EFO' has several questions with regard to the prosumers:
    - If local generation is 100 % self-consumed at a given moment, can the system operators that still require a curtailment for congestion management?
    - Is an exemption also required if P_prod << P_demand?
    - On page 54 it is mentioned that SOGL imposes schedules for PGM B, C, D with not exemption possible through national regulation. This is not our understanding of the text as it states the following: 'as an exception to points (a) and (b), in regions with a central dispatch system, data requested by the TSO for the preparation of its active power output schedule'.
    - In the same line as the previous comment, SOGL article 110(3) seems to imply that national regulation can exempt some SGU from designating a scheduling agent.
- Page 20: The consistency between the intraday market access and scheduling deadline needs to be ensured. Generally speaking the scheduling deadline should not go beyond any market gate closure deadline for coordinable units.
- Page 20: 'EFO' would like to point out that the re-dispatching deadline per asset may vary if the unit is warm or cold. This variable will have to be considered if the schedules are required to be firm.
- Page 23, 6.3.3: Elia will update the schedule in case of redispatch or mFRR activation: what will happen other (none contracted) balancing bids?
- Page 23, 6.4 on sentence 'in line with current practice, the scheduling agent should inform'. This is not in line with current practice, 'EFO' doesn't see how market actors could send the set point to Elia
- Page 24: A return to schedule request by Elia will not trigger a correction to the perimeter of the BRP. This can only be applied in case the BRP receives the latest schedule sent by the scheduling agent, and thus balances based on the latest available information. Again, 'EFO' doesn't see how

the grid user could comply with this in case the BSP/Grid User is using 'transfer of energy', and thus has to ensure confidentiality.

- Page 25, 6.4.1: The fact that existing units without real-time metering are still subjected to the scheduling obligation and can thus be subjected to a return to schedule request can be seen as an extreme requirement. Elia mentions that no real-time metering equipment would be required, however if the unit has to be schedulable, some type of remote controlling have to be installed and thus result in additional costs for the grid user.
  This issue also raises some questions on the interpretation and implementation of SOGL:
  - The link is made between articles 111 (obligation of Scheduling Agent) and article 46 (schedule data required). What about articles 45 (structural data) and 47 (real time data)? Is this information also sent also by the Scheduling Agent or by the Grid User?
  - Articles 45 and 46 are applicable on existing unit, but article 47 not?
  - Articles 45, 46, 47 are used to define data exchange in the general requirements for the NC RfG, but the NC RfG is not applicable on existing unit. So, what does this mean for articles 45, 46 and 47?
- Page 27: Why can 'must run' or 'may not run' be applied on PGM, but not on demand? If demand can determine at which price they want to offer balancing bids, they should be able to determine a price offer for 'must run' or 'may not run': Elia can than still decide to impose constraints or not.
- Page 27, 71, §3: How should this be interpreted? If a 'must run' on PMin for a PGM was paid by Elia but during 1 hour in the day the PGM runs above PMin, then the whole payment should be reimbursed?
  It might be interesting to push the PGM to PMax during one or some hours, without that this is making it overall profitable to run the PGM.
  If a 'must run' is paid, it ensures a certainty for Elia: there should be no such thing as reimbursement if conditions change afterwards.
- Page 28: If a PGM is below the 'must run' schedule, it needs to reimburse and pay a penalty; if it is above the schedule, it needs to reimburse. It seems to be very difficult to keep a payment.
- Page 28, 7.1.2: If Elia cancels a must run request before DA GCT, the remuneration should be reimbursed – again unacceptable – as the market might have changed and actions to lock costs, might already have been taken (e.g. buying the necessary fuel); this is even more valid if the 'must run' constraint was initially fixed before D-1
- Page 29, 7.2.2: See comment above.
- Page 29 on 'Interdependency with outage planning amendments': In case of a 'may not run' the PGM should keep its status 'available', otherwise it loses its remuneration; the proposals seems to be incompatible with REMIT as the unit will have to be notified to the market as unavailable due to a TSO request as the unit will not be offering volumes in the day-ahead market.
- Page 30, in the frame: It is not true that if the PGM runs above PMin during one or some hours, this indicates that the PGM is reimbursing all its costs of running: there should be no such thing as reimbursing the Elia payment
- Page 31: Costs of reserve restoration caused by annulment of a 'must run' request are foreseen: this means that there is a procedure described on how reserve restauration is managed?
  Annulment of congestion activation is free of charge to Elia, but the grid user loses possible market opportunities between day ahead and the intraday annulment
- Page 32: Elia mentions that 'the scheduling agent will be held liable for any consequences and will have to remunerate to ELIA the costs of the actions taken by ELIA to prevent or correct the insecure situation on the grid'. This seems to be inconsistent with the general remark made in 'Future roles and responsibilities', notably 'the grid user remains responsible for assuring that the third party operates in compliance with the regulation'. In addition 'must run' and 'may not run' requests which are not respected in real-time may lead to insecure situation on the grid. However it is impossible for a generator to guarantee that a unit would not trip. These situations should be included in the document.
- Page 34, 8.1.2: Why can demand facilities voluntarily bid for redispatching? Same requirements should exist for all.

One could require from demand to at least bid the same volumes for redispatching as for balancing.

Why are demand facilities considered as non-coordinable, even if they are offering in the balancing market? This is not consistent.

- Page 34: If balancing is not mandatory on category B units but redispatching is, discrepancies are created. Offering for redispatching from category B assets could be voluntarily as well.
- Page 35, frame: Assets that are bidding in balancing services will be considered as coordinable units. Indeed, but why does that not apply for demand (see above): this is not consistent.
- Page 38: Elia mentions 'For information, in the above case, ELIA also intends to use the same MW schedule as a baseline for mFRR activations'. When a baseline is used for perimeter correction - congestion or transfer of energy - the schedule should reassemble the realized consumption. Elia mentions that only deviations that go against a possible congestion will be submitted to a return to schedule. It would mean that certain deviations will be seen as part of the activation and lead to a remuneration of the BSP without him taking action. In addition the BRP will receive a perimeter correction for a not realized deviation which results in an imbalance position opposite to the congestion or balancing signal. 'EFO' advises that in case activations are only know shortly before activation, the realized consumption is considered as applied currently for bidladder (last Qh). When activations are known longer before, the maximum effort should be done to avoid gaming behavior.
- Page 39: 'EFO' doesn't understand why one could not have implicit for redispatch and explicit for balancing as this is what is being allowed for demand and PGM for category B
- Page 45, on bid size option 2: With regard to the scheduling limits – this is the same as implicit bidding – there are again not the same requirements for demand and production. Why can it work for one and not for the other?
- Page 47, frame: Why does a PGM need to bid at cost while the demand facility can bid at opportunity cost?
- Page 48, below the frame of §3: if upwards flexibility is being activated at cost by Elia, the opportunity to market in the intraday markets is taken away without this being compensated: what is stated is wrong.
- Page 50, underdelivery is considered as unacceptable and will be severely penalized: Shouldn't this penalty be cost reflective or in relation to incurred damages? This will lead to a totally asymmetric relationship in which a PGM is remunerated at cost, but bears enormous risks.
- Page 50: With regards to the compensation bid for congestion, 'EFO' has doubts on the proposed cross-border market access of Elia. When Elia will use cross-border market access, it will block capacity for the market. Because of this lower available capacity market parties might face more difficulties in solving their residual imbalances and therefore push imbalance prices in the Belgian zone. To our understanding this solution should only be allowed in extreme situations. Similar considerations can be formulated regarding the use of non-reserved balancing capacity for congestion reasons. Overall it appears incoherent to state that the TSO will avoid an impact on the imbalance position of re-dispatching actions while the means to deal with the compensation of the re-dispatching are increased.
- Page 50: Elia will no longer activate compensation bids in parallel but in a serial way aiming at the most beneficial way both from a technical and economical point of view. This will be combined with increased sourcing possibilities, e.g. (cross-border) day ahead, intraday or balancing markets and reserve market. Therefore, 'EFO' is of the opinion that the rules that Elia will apply should be clearly communicated towards the market. In addition these rules should be monitored and evaluated from time to time to see if the bring the highest added value towards society and avoid speculative bidding behavior by the TSO. To the understanding of 'EFO' first any flexibility available within the country will be addressed/activated before cross-border deals will be performed for (local) congestion management.

Part III – Congestion Risk Indicator

- Where is it described that if one starts up a unit for reserve obligations, one does not want to buy it back at cost and receive the power in such case. If due to redispatching one cannot fulfill its reserve obligations, one should be exempted and a reserve restauration procedure should be put in place.
- The effect of the congestion management on the reserve obligations should be further detailed.
