Cost Benefit Analysis for Imbalance Settlement Period Harmonisation

A GUIDEBOOK PREPARED FOR ENTSO-E

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Introduction

Context

The draft Network Code for Energy Balancing (NC EB) requires all TSOs to develop a proposal to harmonise the main features of imbalance settlement,[1] subject to approval by all NRAs.[2] However, the Imbalance Settlement Period duration falls outside this proposal and may be drafted into the final version of the NC EB. ACER has reviewed the draft NC EB and has proposed that the Imbalance Settlement Period duration be harmonised at 15 minutes. ACER also proposes that its recommendation on the Imbalance Settlement Period is assessed by a cost benefit analysis (CBA) to be undertaken by ENTSO-E before the NC EB enters the Comitology process.

ENTSO-E asked Frontier and Consentec to develop a general methodology for TSOs in relation to the completion of the CBAs envisaged in the NC EB, and a specific methodology for the completion of the CBA for ISP harmonisation:

- **General methodology for performing CBAs** – this task covers the development of a general framework for performing a CBA in the context of the NC EB[3].
- **Specific methodology for the CBA for ISP harmonisation** – this task covers the development of a specific methodology for performing the CBA for ISP harmonisation. This methodology should be consistent with the design of the general methodology for performing CBAs[4].

Both documents have been made available to stakeholders.

Following on from the development of these documents, ENTSO-E has asked Frontier to support the process of undertaking a CBA of a change in ISP. To secure relevant inputs to the CBA process, ENTSO-E is asking for data from stakeholders across Europe, via a questionnaire. This document provides guidance to support those stakeholders filling in the questionnaire, and therefore should be read in conjunction with the questionnaire spreadsheet.

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1 Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2014 of 20 July 2014 on the Network Code on Electricity Balancing, Annex II, Article 24.

2 Ibid. Article 6(6).

3 This report was finalised before ACER made its proposals for the NC EB.

4 Upon publication, this will be available here: https://www.entsoe.eu/major-projects/network-code-implementation/cba-imbalance-settlement-period/Pages/default.aspx.

Content

This document is structured as follows:

- In section 2, general principles applying across the survey are set out.
- In section 3, guidance is provided for the assessment of costs related to ISP harmonisation.
- In section 4, guidance is provided for the assessment of benefits related to ISP harmonisation.

Stakeholders may find some of the information requested difficult to provide and in these cases we would ask that stakeholders make their best estimate.

Process

This survey will be circulated to stakeholders by ENTSO-E, and relayed by member TSOs.

Stakeholders are asked to provide their answers to the survey by 14th January 2016.

Responses should be sent directly to ENTSO-E via email to the following address: cbaisp@entsoe.eu.

The survey tool has been designed to enable stakeholders to include all their answers and comments in the excel file provided alongside this guidebook. Should they wish to do so, stakeholders can also provide additional comments alongside the excel file.

Support will be available to stakeholders throughout the survey period. In particular, questions should be sent to: cbaisp@entsoe.eu. Answers to questions will be provided either on an ad-hoc basis or in groups in the FAQ section of the dedicated website (depending on volume of questions and scope for grouping questions).

Analysis of responses

Upon receiving stakeholders' responses, Frontier Economics will undertake a critical review and QA of submissions. The precise type of analysis that will be required to complete the CBA will depend on volume and quality of responses received. Frontier Economics anticipate at least the following:

- **Cross-checking.** Frontier Economics will compare and contrast submissions from similar organisations (e.g. TSOs of countries with similar market arrangements, suppliers from the same country, etc.) to provide comfort regarding the robustness of responses or, where applicable, identify outliers.

- **Sense-checking.** In the time set aside for the CBA, Frontier Economics will not be deriving its own bottom-up view on each of the costs and benefits. However, it will rely on existing datasets and proprietary modelling tools and results to sense-check the information provided by stakeholders where applicable.
- **Complementary analysis.** Where the previous steps have led to questioning the validity of survey responses, Frontier Economics will aim to interact with stakeholders to improve the quality of data. Should this not be achievable, Frontier Economics will reserve the right not to take into consideration some survey responses – in this case this will be duly documented. Where Frontier Economics departs from survey responses, it will use either other stakeholder contributions or ad-hoc analysis to fill in the gaps in the evidence based required to carry out the CBA.
- **Scaling up.** It can be expected that the response rate for the survey will not cover 100% of the relevant market areas and stakeholder types. Frontier Economics will therefore be looking to scale up estimates derived from responses in order to reach the appropriate scope for the CBA. As discussed in more detail in section 1.1.3 below, this requires access to a number of indicators on the scale of respondents' activities relative to the relevant market area. Some of this information might be confidential and ENTSO-E and Frontier Economics are committed that this confidentiality be preserved (see below).

Stakeholders should note that, in light of this process, the accuracy and transparency of responses will be key for the robustness of the CBA. Stakeholders are therefore asked to provide detailed comments about the approach they have used and assumptions they have taken in each aspect of their responses to the questionnaire. Further indications for the nature of assumptions required are provided in this guidebook.

Confidentiality

To the largest extent possible, the questionnaire aims to ask stakeholders for public data, but some of the aspects of the methodology demand access to confidential data. ENTSO-E[5] will treat all information provided by individual stakeholders as part of the survey as confidential. ENTSO-E may share data, including confidential data, with ENTSO-E member TSOs but only on the basis that the data being shared is treated as confidential by ENTSO-E member TSOs.

5 And the parties engaged by ENTSO-E in relation to the CBA, in particular Frontier Economics

Information gathered through the survey may be published in an aggregated form, e.g. by stakeholder group and by country.

1 General principles

This section provides general information on the scope of CBA and guidance to fill out section 0_Respondent_Details and 1_Current_system of the survey.

1.1 Scope for the CBA

1.1.1 Time frame

The analysis of costs and benefits will be carried out over a time horizon of c. 10 years after implementation date. ACER's recommendation is that any changes to ISP duration are made by 1 July 2019. For simplicity, the CBA will assume that the necessary actions to implement the change are taken by the end of 2019.

Therefore, we ask for information related to ongoing costs and benefits for the years 2020 and 2030 in the questionnaire, and will interpolate between the results for these years in the CBA process itself.

All information about ongoing costs and benefits requested in the questionnaire should be provided on an annual basis. In particular:

- All volumes should be summed across ISPs / hours / days, to sum to yearly volumes;
- All price information should be submitted as yearly volume weighted averages.

In addition, we ask for one-off capital costs related to implementing the change. These costs may be incurred in the years leading up to the change to ISP duration, in keeping with the timeline for implementation stakeholders agreed would be assumed in the CBA. For the purposes of implementation we assume that the NC EB would have passed through the Comitology process and entered into force at the end of 2016[6]. This would give stakeholders two and a half years from when they knew the requirements of any change imposed by the NC EB to the date by which the change had to be implemented.

1.1.2 Geographic scope

Stakeholders from EU+3 (i.e. the EU + Switzerland, Norway and Lichtenstein) countries are invited to respond to the survey, as listed in **Table 1**. Stakeholders should note that the drop-down menu for geographic scope allows stakeholders

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6 We recognise that entry into force might occur later than the end of 2016 (e.g. mid 2017). Stakeholders are invited to provide their view on the impact for the timing of implementation of a change in ISP duration.

from the UK to respond either for Great-Britain, or for Northern Ireland. This aims to reflect that GB and NI (both parts of the UK) have different balancing market and imbalance arrangements operated by different central bodies. Stakeholders should ensure that all the answers provided throughout the survey will remain consistent with the choice made here in relation to geographic scope. Should stakeholders have some information available only at the scale of the UK, they should provide this information and indicate the corresponding scope in comment boxes. This information will be allocated to NI/GB when the CBA is performed.

All stakeholders should respond to the questions about geographic scope.

Table 1. Areas included in the scope of the CBA

AT	Austria
BE	Belgium
BG	Bulgaria
CH	Switzerland
CY	Cyprus
CZ	Czech Republc
DE	Deutschland
DK	Denmark
EE	Estonia
EL	Greece
ES	Spain
FI	Finland
FR	France
GB	Great Britain
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LI	Lichtenstein
LT	Lithuania
LU	Luxemburg
LV	Latvia
MT	Malta
NI	Northern Ireland
NL	Netherlands
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
SE	Sweden
SI	Slovenia
SK	Slovak Republic
UK	United Kingdom

General principles

Source: Frontier Economics

Stakeholders are asked to reply to the survey for the country in which they operate. Should a stakeholder operate in multiple countries, then one survey should be filled in for each country of operation. Question 0.1.1 asks stakeholders to specify the country to which each survey applies.

The list of countries provided in **Table 1** reflects the scope of the proposed changes and therefore the CBA itself. However all ENTSOE members can participate in the survey should they wish to – in this case they should choose the country for which they wish to provide a view.

Currency

The survey should be completed in either Euros or the local currency. Stakeholders should indicate the currency used in their response the survey in section 0.1.2. This currency will be assumed to be the same across all information provided by the stakeholder in the survey.

If stakeholders have converted to Euros from another currency in their response, stakeholders should indicate the other currency and the exchange rate underlying their response to the survey in section 0.1.3.

Inflation

Stakeholders are expected to fill in the survey with costs estimated on a nominal basis (i.e. money of the day). We expect that stakeholders would make their own assumption about inflation when projecting costs and benefits to 2020 and 2030. Where answers reflect an inflation expectation on the part of the stakeholder, this expectation should be specified in section 0.1.4 of the survey. This will enable comparing survey responses on a like-for-like basis across stakeholders (i.e. separating out between gaps due to differing views on inflation from gaps due to differing views on costs and benefits). Where stakeholders do not provide the inflation assumption underlying their responses, otherwise ENTSO-E will consider that the stakeholder has assumed an inflation of zero % across the period.

1.1.3 Business characteristics

In section 0.2, stakeholders are invited to indicate which role best describes their business activity.

The survey envisages the following roles:

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- 0.2.1 Aggregator[7]
- 0.2.2 Broker
- 0.2.3 Data provider
- 0.2.4 DSO
- 0.2.5 End consumer (metered[8])
- 0.2.6 Generator (metered)
- 0.2.7 Imbalance settlement agency (non-TSO)
- 0.2.8 Market operator
- 0.2.9 Meter provider
- 0.2.10 Metering service provider
- 0.2.11 National Regulatory Authority (NRA)
- 0.2.12 Power exchange
- 0.2.13 Retail supplier
- 0.2.14 Trader
- 0.2.15 TSO
- 0.2.16 Other (please specify).

Multiple roles

Two alternatives are available to stakeholders with several roles:

- The stakeholder can fill in one survey for each role – this will allow the stakeholder to allocate costs and benefits in a more detailed way to individual roles;
- The stakeholder can fill in a unique survey and specify in section 0.2 how they wish costs and benefits to be allocated across their roles. Stakeholders should note that, in this case, all costs and benefits will be allocated uniformly across their roles, based on the % specified in this section.

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7 Aggregators are defined here as legal entities that aggregate "the load or generation of various demand and/or generation/production units" (https://ec.europa.eu/energy/sites/ener/files/documents/EG3%20Final%20-%20January%202015.pdf)

8 Large, metered consumers only are expected to provide answers to this survey.

Scope of answers to the survey

The majority of questions in the survey relate to a particular role and we would expect that most stakeholders would limit their responses to those questions relevant to their role. The figure below aims to identify for each question the roles that would be most likely to hold the relevant information and expertise to respond to the question.

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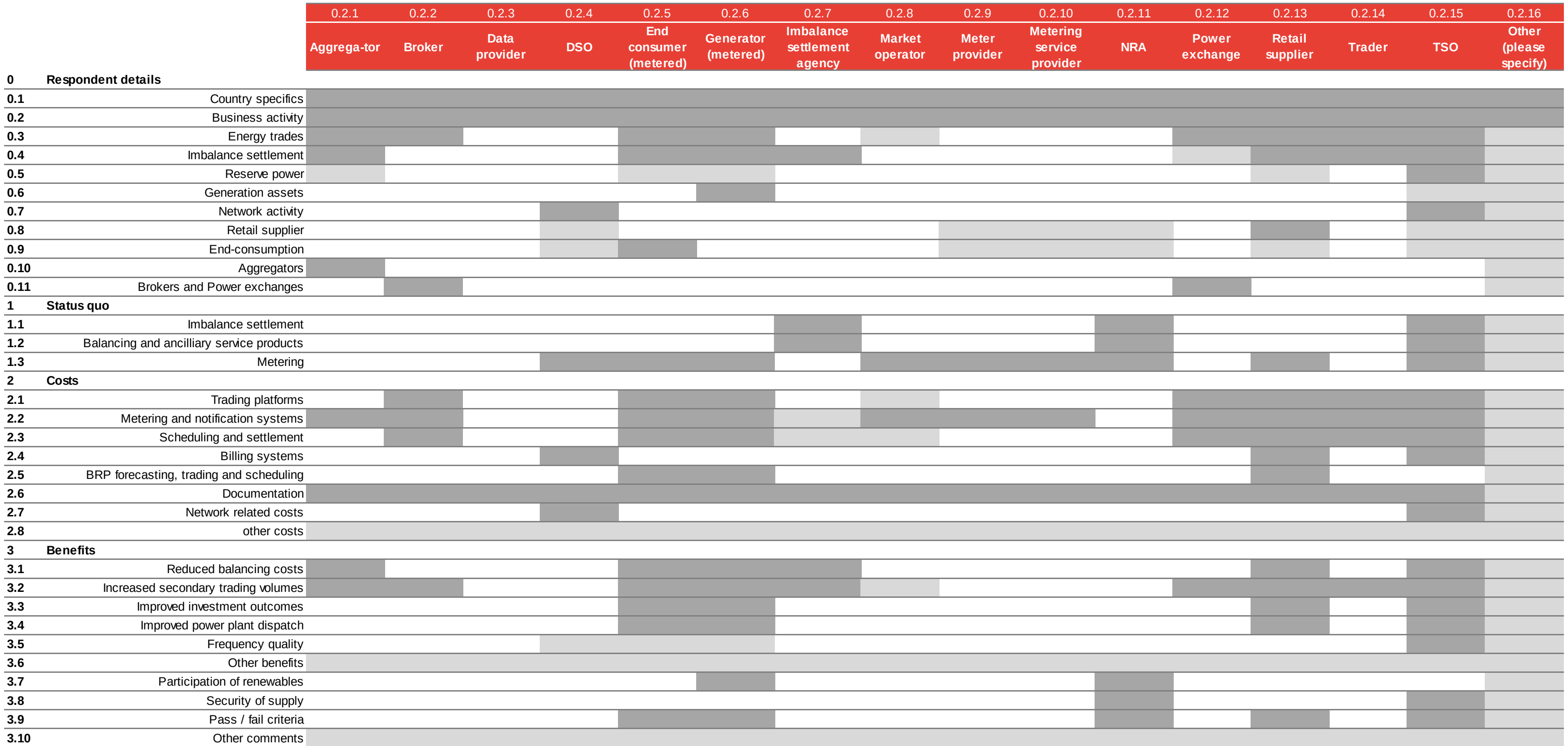
Figure 1. Expected scope of answers to the survey by stakeholder role



Source: Frontier Economics

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However, stakeholders are also welcome to provide their views on costs and benefits even where those relate to roles that they have not selected in section 0.2.

Upon receiving the survey results, Frontier Economics will aim to validate the information provided by all stakeholders. Where comments and information provided are considered to be useful and valid, this information will be used in the cost benefit analysis. Where the information appears less relevant, or where there is a risk of misunderstanding, Frontier Economics will, within the constraints of the overall time available for the CBA, aim to go back to stakeholders for clarification before deciding on the weight that will be given to this information in the cost benefit analysis.

Description of activity

Respondents are asked to provide high-level information to quantify the volume of their activity in respective business lines. This will be mainly used to allow costs and benefits to be scaled to the size of the market as part of the CBA. As discussed above, the expectation is that responses to the questionnaire will not cover the full scope of the CBA: enabling the scaling up exercise by answering section 0.3 onwards of the survey is therefore necessary for the CBA to be completed.

Where stakeholders are asked to quantify their level of activity, volumes should be provided in absolute terms as well as relative to the size of the whole market in the relevant country or geographic area (for simplicity we call this the relevant market area throughout this guidebook).

Stakeholders should aim to provide this information for the most recent full year, e.g. 2014. Where this is not possible, stakeholders should reference in the Comment boxes the time frame over to which their answers correspond.

- **0.3. Energy trades.** Stakeholders are asked to specify here (0.3.1) whether they trade power (either on power exchanges or over the counter) or not. Where relevant, stakeholders are asked to specify the number of trades (0.3.2) and annual traded volumes (adding up volumes bought and volumes sold, in MWh (0.3.3) and in % of the relevant market (0.3.4)), for each of the relevant day-ahead and intraday markets. Stakeholders should aim to provide this information for the most recent full year, e.g. 2014.

  Some of this information can be seen as commercially sensitive by stakeholders. Stakeholders should note that the information is requested because it is necessary to ensure completion of the CBA. In particular, information on trades in day-ahead market will be needed:

  - For scaling up responses in market areas where there is no intraday market;

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- Because the CBA will investigate the possibility that impacts on intraday markets (discussed further below) will leak to the day-ahead market.

- **0.4. Imbalance settlements.** All stakeholders that are directly involved with imbalance settlements (e.g. as BRPs or TSOs) are asked to notify this here (0.4.1)[9]. Stakeholders should clarify in the comment box in which capacity they have answered yes to this question. The information gathered here will serve to cross-check and scale up the analysis of impacts on balancing prices.

  Where relevant, stakeholders are asked to specify the number of imbalance settlement trades they have undertaken (0.4.2) and corresponding energy volumes (in MWh in 0.4.3 and relative to the total volume of imbalances in 0.4.4). In item 0.4.3 TSOs or imbalance settlement operators are asked to specify the total volume of imbalance settlements they facilitate, and in item 0.4.4 they should answer 100% to the extent that they are the sole party responsible for imbalance settlements in the relevant market. Stakeholders should aim to provide this information for the most recent full year, e.g. 2014.

- **0.5. Reserve power.** TSO and parties involved with holding reserves are invited to respond to this section, which will serve to cross-check the assessment of the impact of the change in ISP duration to the cost of reserves held across the market. Stakeholders are asked to specify here (0.5.1.) whether they offer reserve power (or in the case of the TSO to confirm that they tender reserves). If relevant, stakeholders are asked to break down their participation in reserve markets across primary, secondary and tertiary reserves, by specifying for each the number of trades (0.5.2) and average volume bid into the reserve (in MW in 0.5.3 and % of total volume of capacity held in each reserve across the country/market area in 0.5.4). If stakeholders are not able to break down the information across reserve types, they should provide this information in aggregate over all reserves and flag this in the comments box.Stakeholders should aim to provide this information for the most recent full year, e.g. in 2014.

- **0.6. Generation assets.** Stakeholders are asked to specify here (0.6.1) whether they own or operate generation assets. If relevant, stakeholders are asked to specify the number of generation assets they own (in absolute terms and as a % of total assets in the market, 0.6.2 / 0.6.3), the volume of installed net generation capacity (in MW and as a % of installed capacity in the relevant market area, 0.6.4 / 0.6.5). Generators are also asked to confirm

9 Stakeholders should note that this question focuses on the settlement of imbalances – not the procurement of capacity for balancing purposes.

that their meter can record and is read at ISP duration (0.6.6). This information should be provided for 2014, and broken down into transmission-connected and distribution-connected assets. The information will be mainly used for scaling-up purposes.

- **0.7. Network activity.** Stakeholders are asked to specify here (0.7.1) whether they own or operate a power network. If relevant, stakeholders are asked to specify the number of exit (off-take or in-feed) points from the network to other transmission networks (in other balancing regions), distribution networks, generators and end-consumers as of the end of 2014 (in absolute terms in 0.7.2 and % of total exit points on networks in the relevant market area in 0.7.3) as well as the number of meters on the network (in absolute terms in 0.7.4 and % of total meters on networks in the relevant market area in 0.7.5). This information will be used for scaling up purposes as well as to cross-check estimates of changes in metering and network costs.

- **0.8. Retail supplier.** Stakeholders are asked to specify here (0.8.1) whether they operate a retail supply business. If relevant, stakeholders are asked to specify the number of customers they had as of end of 2014 (in absolute terms in 0.8.2 and % of customers nationally in 0.8.3) in 2014, separating the information between customers with meters that are able to be read at the current ISP timeframe and customers with meters that are not able to be read at the current ISP timeframe. Stakeholders are encouraged to provide a break-down of this information across main consumer categories (large industrial and commercial, small industrial and commercial, and domestic). For smaller customers, it is likely that there are fewer meters than there are customers (this is the case if the smart meter roll-out has not been carried out). We therefore ask stakeholders to clarify this if relevant.

  This information will be used for scaling up purposes. Other stakeholders are likely to have information helpful for scaling up as well: for instance NRA or meter operators would be expected to have views on total number of meters. These stakeholders are invited to report their views in section 0.8.2.

- **0.9. End-consumption.** Stakeholders are asked to specify here (0.9.1) whether they are an end-consumer of electricity. Only those larger customers who are connected directly to the network are expected to submit a response to this survey and section. If relevant, stakeholders are asked to specify whether they settle their imbalances centrally/via an aggregator or via their retail supplier (0.9.2), the number of ISP meters installed on their sites as of 2014 (in absolute terms (0.9.3) and as a % of total ISP meters installed nationally (0.9.4)), the number of non-ISP meters installed on their sites as of 2014 (in absolute terms (0.9.5) and as a % of total non-ISP meters nationally (0.9.6)), and the annual volume of their energy offtake in 2014 (in MWh (0.9.7) and % of total demand 0.9.8)). This information should be provided separately for sites connected to the transmission network and sites connected to the distribution network.

Other stakeholders are likely to have information on the total volume of end consumption by meter type – e.g. meter operators, NRA… - whereas some individual end-consumers might not have this information. Relevant stakeholders are therefore asked to provide their views on items 0.9.3, 0.9.5 and 0.9.7 at the scale of the whole market, and this information will be used to scale up that provided by end-consumers.

- **0.10. Aggregators.** Stakeholders are asked to specify here (0.10.1) whether they are active as an aggregator on the wholesale market for power. If relevant, stakeholders should specify the size of the portfolio of capacity they aggregated, in MWh (0.10.2) and MW (0.10.4) and as a % of total generation and total capacity (resp. 0.10.3 and 0.10.5) in the market, in 2014.

- **0.11. Brokers and power exchanges.** Stakeholders are asked to specify here (0.11.1) whether they are active as a broker or a power exchange. If relevant, they are asked to specify for each of the day-ahead and intraday market the number of trades in absolute terms (0.11.2) and % of total trades in the market (0.11.3) and traded volumes in absolute terms (0.11.2) and % of total trades in the market (0.11.3) they were responsible for in 2014.

1.1.4 File naming conventions

Stakeholders are asked to name each response to the survey as follows:

"ENTSOE-survey-ISP-harmonisation-[COUNTRY CODE]-[ACTIVITY CODE]-[COMPANY].xlsm"

Where

- the country code should match the list provided in **Table 1**;
- the activity code (0.2.1, 0.2.2…) should match either a single activity or the activity to which the highest share of benefits has been allocated in section 0.2 in the survey; and
- the company name should be written in capital letters and without spaces.

1.2 Planning cases

1.2.1 Alternatives considered for ISP harmonisation

Although ACER's proposal is to harmonise ISP duration at 15 minutes, the CBA is intended to assess this proposal to understand whether it is the best choice of ISP duration or whether alternative proposals would be better. For this reason multiple factual scenarios are considered, and not just a single scenario of moving to 15 minute ISPs throughout Europe.

Four factual planning cases have been defined, which will be compared in the CBA. The CBA for each planning case will be assessed by comparison to the counterfactual planning case – where ISPs remain as of today. The CBAs for the four planning cases (relative to the status quo) will then be compared against each other.

Figure 2. The CBA will consider 5 alternative planning cases, including counterfactual

	Description
1 Counterfactual - All ISP remain as of today	• All regions remain with today's ISP (modified by changes *already decided on*)
2 All regions go to 15 min ISP	• Countries with 15 min ISP remain untouched • All other countries change to 15 min ISP
3 If change required, move to 15 min	• Countries with 60 min ISP move to 15 min • Countries with 30 min ISP remain unchanged
4 If change required, align with neighbours	• Countries with 60 min ISP move to either 15 min or 30 min (depending on largest neighbour)
5 All regions to 5 min ISP	• Full harmonisation to 5 minutes

Source: Frontier Economics

Each planning case is described in more detail below. Stakeholders are invited to refer to the methodology document for a more detailed description of how planning cases have been derived.

For each planning case, the only change assessed in the CBA will be that of the ISP duration of the period alone. In particular, the CBA will assume:

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- No change in the actual imbalance pricing algorithm or more generally in any other part of the imbalance settlement process[10];
- No change in gate closure time;
- No change in Final Physical Notification content, process or timing;
- The market time unit (MTU) for the intra-day market changes in line with the ISP duration; and
- The MTU for the day-ahead market remains as it is today.

In practice, if we consider the example of the move from a 30-minute to a 15-minute ISP duration, stakeholders should consider that:

- A number of trading products become available on the intraday market with delivery windows equal to 15 minutes (e.g. 14.15 to 14.30);
- The amount of time elapsed between Gate Closure time and start of delivery periods does not change – if this was 30-minutes previously, then in the planning case it is still the case that gate closure occurs 30 minutes before start of delivery. This will require new gate closures to be created across the day (e.g. 13.45).

Stakeholders should aim to remain consistent with these assumptions throughout their answers to the question. Should stakeholder take the view that not all these assumptions are appropriate, they should report this in comment boxes and describe how a change in assumption would be likely to impact cost and benefit estimates.

We discuss in section 2 assumptions relative to changes in metering granularity.

Status quo – all ISPs remain as of today

As a starting point, the CBA requires a thorough understanding of the status quo, that is to stay the state of the world that will prevail absent ISP harmonisation.

In the status quo, ISP durations would be assumed to be equal to those observed as of 2014 for all countries, as depicted in **Figure 3**.[11]

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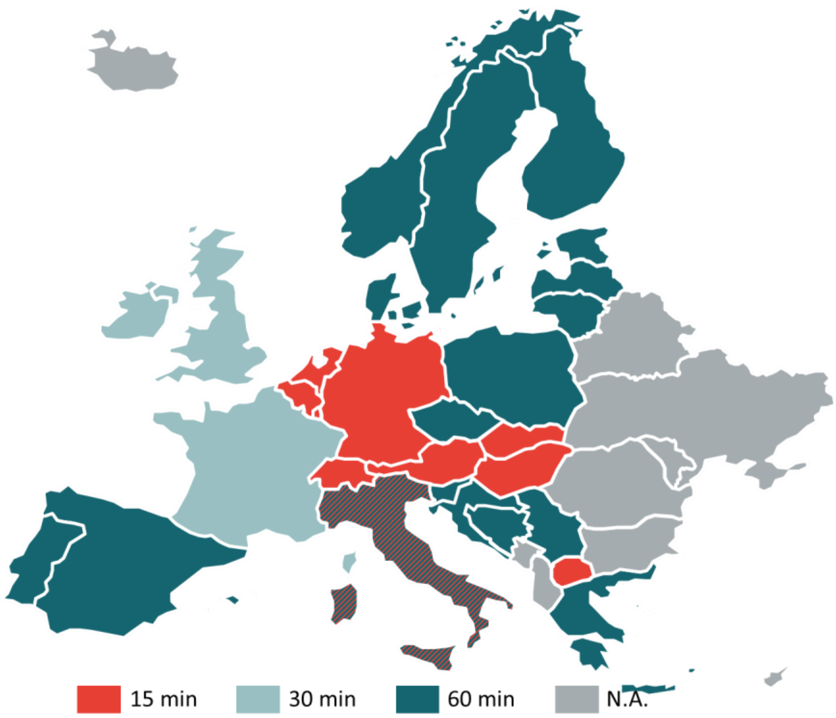
10 Throughout their responses to the questionnaire stakeholders are asked to describe how their answers relate to the imbalance settlement process in order to ensure a consistent approach is taken by all stakeholders when assessing the costs and benefits that relate to imbalance settlements.

11 The NC EB would not apply to the transmission networks of Bosnia, Serbia, Kosovo and FYROM, which are included in the map. However, these countries are likely to be affected by the choice of ISP duration for their neighbours. While we suggest the scope of the CBA be limited to the EU 28 plus Liechtenstein, Norway and Switzerland, there could be an argument for extending it further to include non-EU countries in the Balkan region or elsewhere. See further below for a discussion of the geographic scope.

Figure 3. ISP duration in the status quo



Source: ENTSO-E WGAS, Survey on Ancillary services procurement, Balancing market design 2014, Jan 2014. Also TSO websites.

Note: Italy has a 60 minute ISP with the exception of Balancing Service Providers (BSPs) that are required by regulation to have a 15min ISP.

Changes already decided

The CBA will also consider as part of the status quo any changes decided prior to the CBA being carried out. This includes any changes to ISP duration as well as other changes potentially driving the costs and benefits of changes to ISP durations, such as:

- Smart meter roll-out;
- Changes to metering rules;
- Changes to imbalance price setting rules;
- Definition of ancillary services product;
- Physical notification rules;
- Etc.

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Survey

Section 1_Current_System of the survey aims to document the status quo in each relevant country.

- In section 1.1 of the survey, TSOs or imbalance settlement responsible organisations as appropriate are asked to describe arrangements pertaining to imbalance settlement in the status quo:
  - In 1.1.1: duration of the ISP, accounting for any changes to the ISP duration that have already been decided on. This information should be provided in minutes.
  - In 1.1.2, imbalance price setting rules and any changes foreseen in those rules.
  - In 1.1.3, gate closure time in the intraday market as per current arrangements or, where relevant, as per changes that have already been decided on[12]. This information should be provided in minutes.
  - In 1.1.4, granularity of final physical notifications, as per current arrangements or, where relevant, as per changes that have already been decided on. This information should be provided in minutes.
- In section 1.2 of the survey, stakeholders are asked to describe balancing and ancillary services products in the status quo, including:
  - In 1.2.1, the arrangements in relation to the procurement of balancing products;
  - In 1.2.2, the timescale for product delivery, in seconds;
  - In 1.2.3, the duration of the products in minutes;
  - In 1.2.4, the rules for participation in balancing service markets;
  - In 1.2.5, whether the TSO typically takes pre-gate closure balancing action and what this typically consists of;
  - In 1.2.6, any non-monetary incentives stakeholders might face to balance.

12 In some markets, there might be a specific Gate Closure time for the Balancing Mechanism/Market which effectively sets the end of trades that can be notified and taken account of in imbalance settlement. Where this is the case stakeholders should specify here the Gate Closure time for balancing purposes.

TSOs, other imbalance settlement responsible organisations and NRAs are expected to fill in this section. Other stakeholders are welcome to provide their understanding and views on the items described above as well.

- In section 1.3. of the survey, stakeholders are asked to describe arrangements relative to metering in the status quo, including:
  - In 1.3.1, the status of the roll-out of smart meter:
    - whether a decision has been made to roll out smart meters; and
    - the scope of the roll-out: customer groups, corresponding number of meters that would need to be replaced and number of meters that would need to be reconfigured remotely, target penetration rate…;.
  - In 1.3.2, the granularity of metering subsequent to smart meter roll-out, in minutes, and per customer group where granularity continues to differ across customer groups – in particular this should specify whether customers will be metered at ISP granularity;
  - In 1.3.3, the location of meters with ISP granularity (transmission / distribution network; generations, end-user customers).
  - In 1.3.4, the average timeframe for meter replacement subsequent to the roll-out, in years(either as a result of a meter having reached the end of its useful life or having failed accuracy checks) ;
  - In 1.3.5, the timeframe for meter calibration[13], in months.

  DSOs, TSOs, retail suppliers, end-consumers (metered), meter providers, meter service provides and NRAs are expected to fill in this section. Other stakeholders are welcome to provide their understanding and views on the items described above as well.

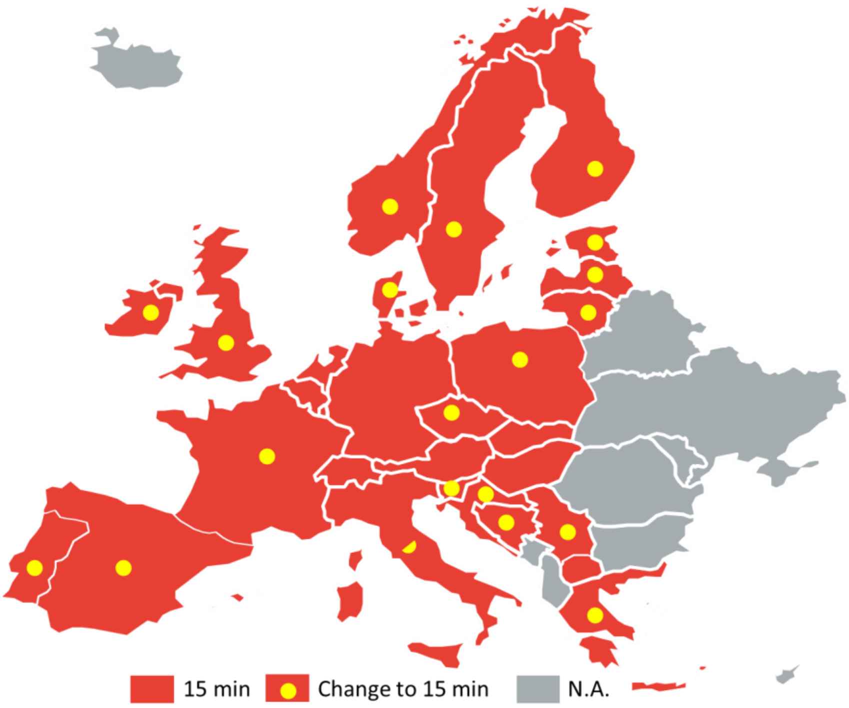
Comment boxes are provided for each of these items. In particular, stakeholders should flag where the status quo involves some changes (already decided on) relative to the arrangements currently in place.

Planning case 2 - Full harmonisation to 15 minutes

Under full harmonisation, all ISP durations are aligned to 15 minutes across the EU+3. As **Figure 4** shows, in this planning case a change of ISP will be required in 20 countries (including Italy).

13 Calibration corresponds to the requirement to check that meters continue to provide accurate readings across their lifetime. Meter calibration can be scheduled according to technical recommendations or, as in the case in Germany, in keeping with local regulation in this area.

Figure 4. ISP duration under harmonisation to 15 minutes



Note: Italy has a 60 minute ISP with the exception of BSPs that are required by regulation to have a 15min ISP. Therefore, Italy would need to change the ISP for non-BSPs to 15 minutes under this case.

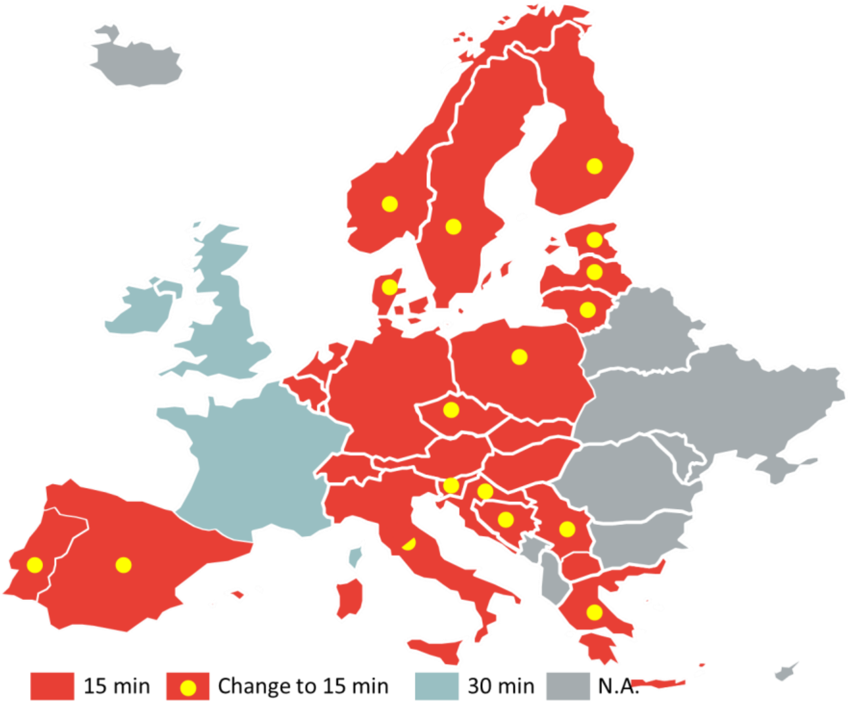
Planning case 3 - Harmonise to 15 minutes only those currently at 60

In this case, all countries currently with an ISP of 30 minutes or shorter retain their ISP duration, while countries currently with an ISP of more than 30 minutes reduce their ISP duration to 15 minutes.

This planning case has been derived with the potential expected that it might allow to minimize costs by changing ISP duration for as few countries as possible, while conforming to the framework guideline proposal of a maximum ISP of 30 minutes. This planning case will thereby test whether net benefits in the CBA are maximised by trying to minimise costs. The rationale for this planning case should however not influence stakeholders' views on costs and benefits.

As **Figure 5** shows, in this planning case the ISP would be changed in 17 countries (including Italy).

Figure 5. ISP duration under harmonisation to 15 minutes of only those currently at 60



Note: Italy has a 60 minute ISP with the exception of BSPs that are required by regulation to have a 15min ISP. Therefore, Italy would need to change the ISP for non-BSPs to 15 minutes under this case.

Planning case 4 – harmonisation by matching ISPs in neighbouring countries

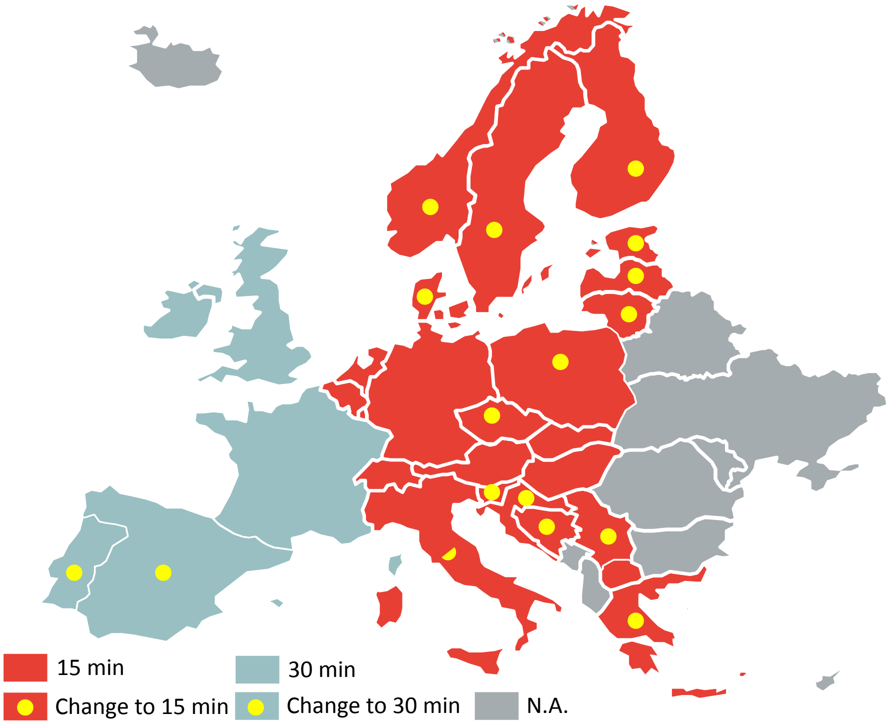
In this planning case, countries that currently have an ISP duration higher than 30 minutes would change ISP. However, they would change to have the same ISP duration as the ISP duration of their largest neighbour, i.e. they do not necessarily all change to a 15 minute ISP as with the previous planning case.

As **Figure 6** shows, in this planning case the ISP would be changed in 17 countries (including Italy):

- Spain and Portugal would align their ISPs with France, resulting in one harmonised south-western region with 30 minute ISPs.
- All countries in central Europe move to an ISP of 15 minutes, as is already the case in Germany and other countries in the region.
- The Nordic and Baltic countries would shorten their ISP to 15 minutes.

General principles

Figure 6. ISP duration under harmonisation to largest neighbouring country



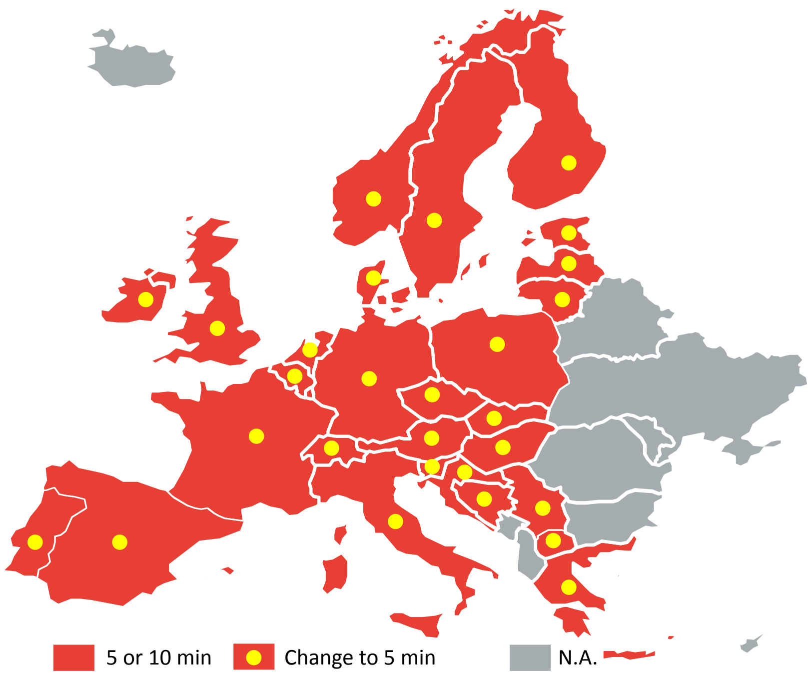
Note: Italy has a 60 minute ISP with the exception of BSPs that are required by regulation to have a 15min ISP. Therefore, Italy would need to change the ISP for non-BSPs to 15 minutes under this case.

Planning case 5 - Harmonise and reduce all regions to 5 minute-ISP

In this planning case, ISPs are harmonised and reduced in the same instance. The CBA will consider the impact of ISPs being reduced to 5 minutes across countries. The reason for including this ISP is to test whether there are benefits to a very short ISP (consistent with the despatch time horizon used in some markets outside Europe) over and above those of complete harmonisation to a 15 minute ISP.

As **Figure 7** shows, this requires that all countries in the scope change their ISP.

Figure 7. ISP duration under harmonisation to 5 minutes



It was also envisaged to consider the costs and benefits of harmonising and reducing ISP duration down to 10 minutes across countries. In order to contain the amount of information asked from stakeholders it was decided that the survey would focus on the 5-minute planning case. Stakeholders are however invited to provide their views as to how the costs and benefits from moving to a 10-minute ISP duration might differ from those which they have estimated for the move to a 5-minute ISP duration (see Comment boxes at the right of costs and benefits tabs). Where significant differences are expected, stakeholders should explain the reason for these differences and provide as far as possible their expected magnitude.

1.2.2 Survey

In order to enable the analysis for the planning cases described above, stakeholders are asked to provide information on costs and benefits associated with a change in ISP duration to all of 30, 15 or 5 minutes for each relevant country.

- Where the current ISP is 30 minutes, stakeholders should only provide estimates of the costs and benefits associated with the change to a 15- and 5- minute ISP;

- Where the current ISP is 15 minutes, stakeholders should only provide estimates of the costs and benefits associated with the change to a 5-minute ISP.

The CBA would also look to build on the lessons learnt from past instances of reducing the ISP duration to 30, 15 or 5-minutes. Where stakeholders have experience of such a change, they are invited to share their expertise on the costs and benefits. Stakeholders should clarify in the comments boxes that their response builds on past experience and provide appropriate justification for the costs and benefits values they indicate. Frontier Economics and ENTSO-E will take such responses into account when deriving the CBA, with due consideration being given to the specific context of the estimates provided.

2 Assessing costs

In this section we first provide general guidance applicable throughout section 2 of the survey. We then provide guidance specific to each cost item.

2.1 Overview

2.1.1 Principles for cost assessment

Incremental costs

The costs of ISP harmonisation are identified as the change in costs arising from a change in the ISP duration. These are the *incremental* costs.

Conversely, any costs incurred in the status quo should be ignored. These are *sunk* costs. In particular, costs of any changes decided prior to the CBA (e.g. changes to metering rules, imbalance setting rules etc.) should be ignored when filling in the survey.

One-off and on-going costs

The survey also distinguishes between up-front CAPEX costs, which are paid once and not repeated, and on-going OPEX costs, which come in addition to one-off costs and can be repeated. A typical example of ongoing OPEX for this analysis is the cost of data management related to a shorter ISP duration.

Upfront and ongoing costs are reported in a different time unit:

- Upfront CAPEX are reported separately for 2017, 2018 and 2019; together with the depreciation period for these investments;
  - Note that where the depreciation period is shorter than 10 years, the CBA will assume that the investment is renewed after the depreciation lifetime expires. Stakeholders do not need to repeat the investment cost in their estimates.
- On-going OPEX costs should be reported separately for 2020 and 2030.

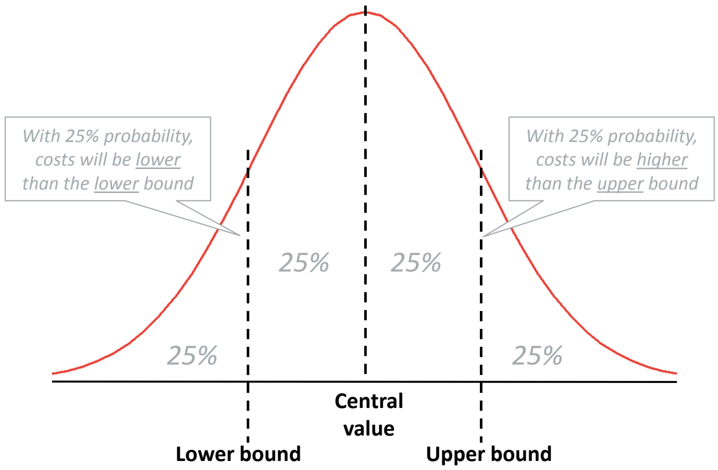
Degree of certainty

Stakeholders are asked to provide estimates for cost items where there is a degree of uncertainty as to what the actual level of costs will be. This is why stakeholders are asked to provide a *range* of costs:

- A lower bound estimate corresponding to costs that are expected to be incurred with a probability of 25% that the estimate will exceed actual costs;

- A central value corresponding to the median estimate for costs;
- An upper bound estimate corresponding to costs that l are expected to be incurred with a probability of 75% that the estimate will exceed actual costs .

Figure 8. Definition of ranges for estimated cost values



Source: Frontier Economics

Documentation

Throughout section 2 of the survey, stakeholders are asked to provide their estimate of costs in local currency.

Stakeholders are asked to justify these cost estimates provided throughout, in the "Comments" column. Stakeholders should also set out their assumptions (e.g. unit costs, fuel costs, quantity, volumes, etc), and explain where they come from. When assumptions are based on a previous experience, the stakeholders should mention it. More generally, they are asked to cite any relevant source that helped them compute the cost numbers.

The detailed descriptions of cost items below provide an approach and structure for assessing each type of costs (e.g. metering costs split across changed and reconfigured metered, and scaled up by number of meters). This is provided for indicative purposes and not replicated in full in the survey. Stakeholders should therefore use the assumption box to describe their approach and intermediate calculations. This also allows stakeholders to suggest alternative approaches to cost assessment if relevant.

Assessing costs

Internal consistency

Stakeholders are asked to provide their views on costs as well as benefits associated with the proposed changes in ISP duration. Stakeholders are asked to ensure consistency of their responses across the cost and benefits sections.

2.1.2 Structure for the assessment of costs

The survey envisages seven categories of costs:

1. Trading platforms
2. Metering and notification systems
3. Scheduling and settlement
4. Billing systems
5. BRP forecasting, trading and scheduling
6. Documentation
7. Network-related costs

In addition, a category "Other costs" is available for stakeholders who have identified costs that do not fall in any of those categories.

Double counting

It may be the case that the costs associated with the change in ISP cannot be broken down into the cost categories envisaged above. In that case, stakeholders should bundle costs across categories and report costs only once. Reporting a cost item twice in the survey will result in double-counting for this particular cost item. Stakeholders should indicate in the "Comments" column where they have bundled cost items in their estimates.

2.2 Detailed guidance

2.2.1 Cost item 1: Trading platforms

This cost item corresponds to the cost of modifying systems and processes to support intraday trading. The cost arises because the reduction in ISP duration will mean that trading platforms used for trading in intra-day timescales will need to be adapted to allow trade of shorter duration products.

Section 2.1 in the questionnaire relates to the assessment of the scale of potential costs. When responding to this question, stakeholders should consider and <u>document</u>:

- 2.1.1. The cost of updates to systems and processes to support trading in shorter time windows. Stakeholders should report here all the costs associated to adapting IT systems to the new ISP duration: for power exchanges, this will include trading support systems, and for participants, this will include trading and risk management systems. This item is a one-off adaptation cost which can be measured in monetary unit (€ or local currency). Stakeholders should specify when this cost is expected to be incurred (e.g. profile of spend over 2017, 2018 and 2019) and the appropriate average depreciation lifetime for new systems / processes.

- 2.1.2. Development of new trading algorithms: Beyond updating existing systems, there could be a need for new algorithms supporting the change in market clearing processes. Stakeholders are asked to report the one-off cost of this change, attributed to 2017, 2018 or 2019 and together with the appropriate depreciation lifetime, and any incremental OPEX to maintain new systems and processes.
- 2.1.3 Other costs.

2.2.2 Cost item 2: Metering and notification systems

This cost item corresponds to the need to update the software or physically exchange the existing meters, update software related to providing the meter data to the operator of the settlement systems, update software related to the notification of physical plans for generation or consumption to the TSO and / or operator of the settlement systems and update the software related to the notification of contractual quantities to the operator of the settlement systems.

It also relates to the incremental ongoing operating costs of handling additional data from meters, and providing additional data on physical plans and contractual quantities.

These costs arise because a shorter ISP duration means consumption data needs to be read over a shorter period and data required by the TSO and data required for settlement must be provided over a shorter period. We assume here that:

- the meters considered here are only those that are read for the purpose of imbalance settlements;
- a meter is changed/reconfigured to match ISP duration only if prior to the ISP reduction the meter reading period matched ISP duration[14]; and

14 Stakeholders should take into account here any planned changes in meter reading period. For instance, if the meter reading period does not currently match ISP duration, but is expected to do so (e.g. subsequent to a smart meter roll-out that has already been decided on), stakeholders should consider the need for an incremental change to the metering period to match the new ISP duration.

- all meters whose meter reading period matched the ISP duration prior to the ISP change are updated to match the new ISP duration.

In practice, this would typically mean that the meters that are changed/reconfigured are meters for:

- generators connected directly to the transmission network, larger generators connected to the distribution network;
- larger end-consumers connected directly to the transmission network; and
- meters that can be found at the points of exit from the transmission network to the distribution network.

These meters would be changed / updated only if they were being read on the same periodicity as the imbalance settlement period duration in the status quo (counterfactual). Meters installed on the premise of smaller customers (which are billed based on profiling) would not be expected to be changed because of the change in ISP duration[15]. We also understand that in a number of markets imbalance settlement and other billing actions use non-ISP metered data (e.g. use profiling) despite the fact that it is technically possible for the corresponding meters to be read at ISP granularity. In this type of case, stakeholders should assume that these meters will not be changed.

Section 2.2 in the questionnaire relates to the assessment of the scale of potential costs incurred by meter providers and metering service providers (including where a stakeholder such as a generator, DSO, TSO or end consumer self-provides these services). When responding to this question, stakeholders should consider and document:

- 2.2.1. The cost of incremental changes to metering systems and processes to provide shorter timeline data relating to metering: depending on the current practices around regular meter calibration, replacement and the updating of consumption profiles, meters will either need to be updated or replaced on site or remotely (see above for indications on scope of meter replacement/updates). Stakeholders should report the one-off cost of replacing/updating the meters, and specify when it is expected to be incurred (e.g. profile of spend over 2017, 2018 and 2019) and the appropriate average depreciation lifetime for new meters.

15 This does not preclude those meters being changed for other reasons such as a mandated smart meter rollout – but the cost of this change should not be attributed to the change in ISP duration.

Examples of the relevant one-off costs include: changing meters, updating meters on site, remotely updating meters, changing meter reading (data collection) systems, and changes to meter management systems (validation, storage and processing of data).

Stakeholders should also indicate the *incremental* annual operating cost (in 2020 and 2030) of handling more metering data. This item should be specified as a monetary unit (e.g. €).

Examples of relevant incremental ongoing operating costs include: the cost of sending the increased amount of data from the metering responsible party to other market parties including the settlement system, the cost of changes to customer reporting systems etc.

In the assumptions box, stakeholders should report the underlying number of meters that they have assumed will need to be changed and reconfigured (separately) and information about other costs.

Stakeholders are invited to fill in this section separately for transmission and distribution, in order to allow for appropriate scaling up of costs.

- 2.2.2 The cost of incremental change to processes required to provide shorter timeline data relating to contract volume notifications for each ISP to the operator of the settlement system. Where relevant, this notification would normally take place prior to gate closure and could be made by generator and load BRPs and in some cases by power exchanges. Stakeholders should report the one-off costs, average depreciation lifetime for new systems and *incremental* annual costs (in 2020 and 2030). This item should be specified as a monetary unit (e.g. €).

- 2.2.3 The cost of incremental change to processes required to provide shorter timeline data relating to notifications of physical generation and consumption plans to the TSO (or other service provider) prior to gate closure. In some cases the shorter ISP duration would require a higher frequency of notifications without changing the granularity of the data provided and in other cases the granularity of the data provided would decrease as the ISP duration is reduced. Stakeholders should report the one-off costs, average depreciation lifetime for new systems and *incremental* annual costs (in 2020 and 2030). This item should be specified as a monetary unit (e.g. €).

- 2.2.4 The cost of changing the systems and processes used to allocate volumes associated with non-ISP based metering to ISPs: stakeholders using non-ISP based metering should record here the upfront and *incremental* ongoing costs associated with converting the metered duration to a deemed meter data for an individual ISP. This item can be measured in monetary unit (e.g. €).

- 2.2.5 Other incremental costs.

Stakeholders should note that the costs estimated here are those incurred by sending parties. Costs incurred by parties that receive the data will be covered in subsequent sections.

2.2.3 Cost item 3: Scheduling and settlement

This cost item corresponds to the need for TSOs, PXs, BSPs, BRPs, imbalance settlement responsible organisations and other stakeholders to adapt their scheduling and settlement systems to the new ISP duration. This cost will likely relate to developing new IT systems or modifying existing systems.

Section 2.3 in the questionnaire relates to the assessment of the scale of potential costs. When responding to this question, stakeholders should consider and document:

- 2.3.1. The incremental cost of changing the systems and processes used to schedule plant: this item relates to the one-off and ongoing costs associated with scheduling over a shorter period of time (e.g. increased frequency in scheduling data).
- 2.3.2. The incremental cost of changing the systems and processes to calculate and settle imbalances to deal with the shorter ISP, and the participant systems which interact with these: this item relates to the one-off and ongoing costs associated with the calculation of imbalances over a shorter period of time (e.g. increased frequency and therefore cost of receiving data).
- 2.3.3. The incremental cost of changing the systems and processes to facilitate the settlement of trades (bilaterally and on exchange) on a shorter ISP basis: this item relates to the one-off and ongoing cost associated with more frequent trades.
- 2.3.4. Data publication costs: this corresponds to the incremental costs incurred by the TSOs and imbalance settlement responsible organisations and other relevant parties to adjust the frequency of data publication to the new ISP duration. This is potentially a one-off and an ongoing cost.
- 2.3.5. Other incremental costs.

2.2.4 Cost item 4: Billing systems

Stakeholders billing their customers according to wholesale price outcomes at the level of the ISP (e.g. for large customers) may need to modify their billing systems. This section deals with the costs of such a change.

The cost is expected to occur for retail suppliers, the operator of the central imbalance settlement, TSOs and possibly DNOs. Where billing at the level of the ISP is carried out by other stakeholders, they should also report changes in billing costs here and indicate in comment boxes the party to which they should be allocated.

Stakeholders should also consider a potential increase in billing costs for transmission and distribution network operators. When considering this, stakeholders should assume that the regulatory framework applicable to network tariff remains consistent with that applicable in the status quo: stakeholders should assume that charging rules remain as of today[16], unless changes have been decided prior to the CBA being carried out[17]. In both cases, stakeholders should specify in the assumptions box how they have treated network billing costs.

Section 2.4 in the questionnaire relates to the assessment of the scale of potential costs in this area. When responding to this question, stakeholders should consider and <u>document</u>:

- 2.4.1. The incremental cost of changing systems and processes to facilitate billing of customers based on the shorter ISP duration: where relevant, stakeholders should report here the one-off cost associated with the change or update in their billing system, and attribute it to 2017, 2018 or 2019 specifying a depreciation lifetime. The ongoing costs related to billing are likely to be incurred in settlement, metering and allocation systems rather than billing systems themselves, but can be reported in this item if relevant.
- 2.4.2. Other incremental costs.

2.2.5 Cost item 5: BRP forecasting and trading

This cost item corresponds to the increased effort made by BRPs to reduce their imbalance position by taking more actions with a finer granularity pre gate closure due to the shorter ISP[18] (Note: it must be assumed that Gate Closure Time remains unchanged from the status quo – it is only the costs and benefits

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16 E.g. if today networks are required to bill on a timescale that matches the duration period this should be expected to remain the case.

17 E.g. change of billing period subsequent to smart meter rollout.

18 See section 3.2.1 for a detailed description of this impact.

of shorter ISP that are being assessed). This encompasses developing new forecasting tools as well as developing new trading and data handling systems.

Section 2.5 in the questionnaire relates to the assessment of the scale of potential costs. When responding to this question, stakeholders should consider and document:

- 2.5.1. The incremental cost of changing the systems and processes to facilitate forecasting and trading on a shorter ISP basis. For BRPs, this includes a one-off cost of developing new forecasting tools or adapting old ones to reduce imbalances. For all stakeholders, there is also a one-off cost of developing trading and data handling systems if the reduction in ISP results in increased trading on the intra-day market to manage imbalance positions. Stakeholders should specify when this cost is expected to be incurred (e.g. profile of spend over 2017, 2018 and 2019) and the appropriate average depreciation lifetime for new systems/processes. Stakeholders should also quantify any incremental OPEX to maintain new processes (e.g. the ongoing cost of greater effort placed on forecasting and increased trading activity and data handling). Stakeholders should estimate these ongoing OPEX costs for 2020 and 2030.
- 2.5.2. Other incremental costs.

2.2.6 Cost item 6: Documentation

This cost item corresponds to the cost of modifying codes and agreements affected by a change to ISP duration.

Section 2.6 in the questionnaire relates to the assessment of the scale of potential costs. When responding to this question, stakeholders should consider and document:

- 2.6.1. The incremental cost of changing centralised market documentation: stakeholders should report here the one-off cost associated with updating country-specific documentation (balancing codes, network codes, ancillary services codes and agreements, documented procedures underlying codes (e.g. for profiling), transportation charging agreements etc). Different stakeholders will be incurring this cost across market areas e.g. this could be the TSO, other imbalance settlement responsible organisations (as is the case in GB), the association of market parties (as is the case in Finland for some parts of the documentation), etc. Stakeholders are therefore asked to specify the costs that they will incur themselves. If they do provide the costs incurred by other stakeholders, they should indicate in the comments box the organisations that are expected to incur increased documentation costs and the level of the costs. Stakeholders should also specify when this cost is expected to be incurred (e.g. profile of spend over 2017, 2018 and 2019).

- 2.6.2. The incremental cost of changing the market documentation: stakeholders should report here the one-off cost associated with decentralised bilateral agreements (e.g. standard contracts for the sale and purchase of power or options). They should specify when this cost is expected to be incurred (e.g. profile of spend over 2017, 2018 and 2019).
- 2.6.3. Other incremental costs.

2.2.7 Network related costs

This cost item relates to the one-off and ongoing costs incurred by the DNOs and TSOs to adapt their network to the shorter ISP.

Section 2.7 in the questionnaire relates to the assessment of the scale of potential costs. When responding to this question, stakeholders should consider and document:

- 2.7.1. DNO and TSO loss procurement costs: this relates to the upfront and ongoing costs associated with adapting the loss procurement system to the new ISP duration;
- 2.7.2. System optimisation and software costs: this relates to the upfront and ongoing costs associated with adapting the optimisation system to the new ISP duration; and
- 2.7.3. Other incremental costs.

3 Assessing benefits

The third section of the survey focuses on assessing benefits arising from each of the planning cases relative to the status quo.

3.1 Overview

3.1.1 Principles for benefits assessment

Incremental benefits

Stakeholders are asked provide their view on benefits arising from the implementation of the planning cases described in section 1.2, and relative to the status quo (including any benefits of the status quo itself expected by stakeholders).

Negative values

Stakeholders are asked to provide their view on the benefits arising from the impact of the change in ISP duration. Stakeholders should note that in principle there could be disbenefits from the change in certain areas (e.g. increase in prices in some markets or a reduction in liquidity due to unbundling of traded products into shorter duration products). Where this is the case, stakeholders are expected to estimate the disbenefit and report it as a negative value. Before entering a negative benefit, stakeholders should make sure that they are not actually netting off some costs from the positive benefit, in which case the cost should be reported in the cost section.

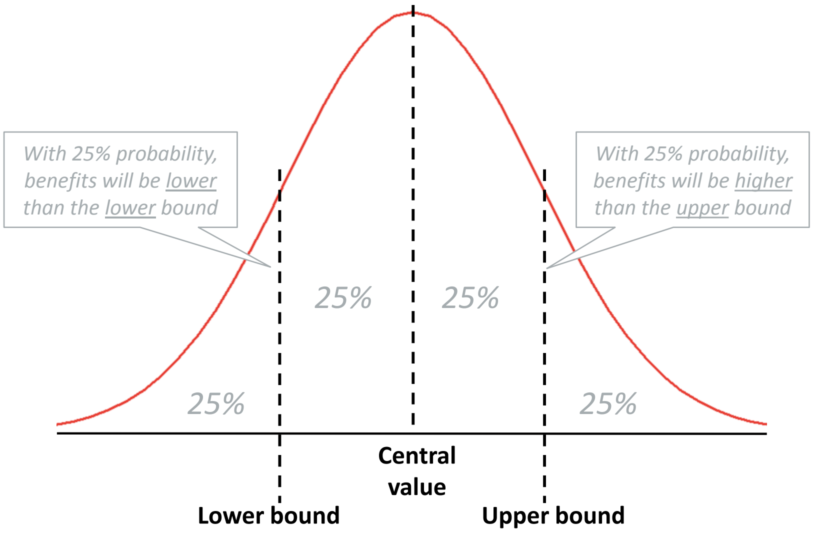
Degree of certainty

Stakeholders are asked to provide estimates for a number of benefits where there is a certain degree of uncertainty as to what the actual level of benefits will be.

This is why stakeholders are asked to provide a *range* of estimates for benefits. However, this range should not represent the maximum and minimum possible outcomes. Rather, stakeholders should estimate:

- A lower bound estimate corresponding to benefits that are expected to be realised with an estimated probability of around 25% that the estimate will exceed actual costs;
- A central value corresponding to the median estimate for benefits in a given year;
- An upper bound estimate corresponding to benefits that are expected to be realised with an estimated probability of around 75% that the estimate will exceed actual costs.

Figure 9. Definition of ranges for estimated benefits values



Source: Frontier Economics

Documentation

Stakeholders are asked to justify the benefit estimates provided throughout section 3 of the survey, in the "Comments" column. In particular, stakeholders should set out their assumptions (unit cost, quantity, volumes, etc), and explain where they come from. When assumptions are based on a previous experience, the stakeholders should explain this. More generally, they are asked to cite any relevant source that helped them to compute responses.

Stakeholders should note that quantifying some of the benefits discussed below requires taking a view on a number of market parameters and their evolutions in the future. This view should reflect stakeholders' expectation in relation to power sector conditions and outcomes in the status quo. Stakeholders should document this view as much as possible in their response, and flag where they believe their estimate of benefits would be particular sensitive to a shift in market conditions.

Internal consistency

Stakeholders are asked to provide their views on costs as well as benefits associated with the proposed changes in ISP duration. Stakeholders are asked to ensure consistency of their responses across the cost and benefits sections.

3.1.2 Structure for the assessment of benefits

The survey envisages two types of benefits:

Assessing benefits

- Monetary indicators, where a monetary value is attributed to assess the magnitude of the benefits – these are listed in **Figure 10** below; and
- Non-monetary indicators, where the assessment will rely on qualitative evidence put forward by stakeholders – these are listed in **Figure 11** below.

Figure 10. Benefit categories

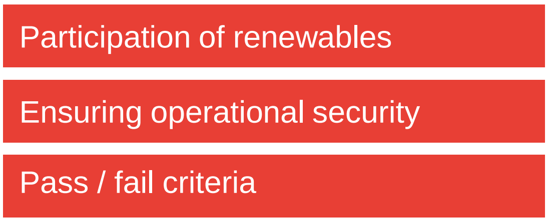
Reduced balancing costs	Lower holdings of reserve capacity by TSOs as a result of BRP action with finer granularity and reduced x-b inefficiency (net of BRP with-holding capacity for this purpose, incl. x-b)
	Reduced use of balancing energy by TSOs as a result of BRP trading and physical actions and reduced x-b inefficiency (net of BRP actions taken pre gate closure, incl. x-b)
	Entry of BSPs as a result of wider access to BMs for existing plant
Increased secondary trading volumes	Increased DA / ID liquidity as a result of BRP actions (incl. x-b trading)
	Increased DA / ID liquidity as a result of greater uniformity of information
	More efficient dispatch due to price effect of improved liquidity in DA / ID markets and shorter duration traded products
Improved investment outcomes	More efficient BRP plant investment as a result of shorter term price signals being more efficient than those price signals provided by TSOs (through BMs and imbalance prices)
	More efficient BRP plant investment as a result of improved liquidity in DA / ID markets

Source: Frontier Economics

In addition, a category "Other benefits" (3.5) is available for stakeholders who have identified benefits that do not fall in any of the categories listed in the questionnaire. In particular, stakeholders should report here any benefits linked to the objectives of the NC not captured in the list above[19].

19 Although the CBA sits outside the NC, the CBA methodology uses the same objectives as in the NC.

Figure 11. Non-monetary indicators



Source: Frontier Economics

Detailed guidance is provided for the assessment of each of those potential benefits below. Stakeholders can also refer to the report *Cost Benefit Analysis for Electricity Balancing – ISP harmonisation methodology* for a more detailed discussion of the drivers of benefits, the associated welfare effects and transfers across stakeholders.

3.2 Detailed guidance

This section provides detailed guidance on how to fill in the 3_Benefits section of the survey. It is important that the benefits included by respondents on the questionnaire are consistent with the costs those respondents have included on the previous section of the questionnaire(e.g. if the benefit requires full ISP metering, then the costs of full ISP metering should be quoted).

3.2.1 Reduced balancing costs

Section 3.1 of the survey deals with the potential savings from reduced balancing costs subsequent to a change in ISP duration.

Sections 3.1.1 to 3.1.6 serve to break down the potential savings, following the rationale and assumptions described below. Stakeholders are invited to comment on those assumptions in the survey. If relevant, an alternative assessment of benefits can be provided in the "other" section.

Stakeholders should note that, in line with the general principles of the CBA, only those benefits that accrue due to the change to ISP duration should be taken into account in the response. For example, where an over-arching rule such as an n-1 criteria prevents a TSO from reducing the amount of operating reserves held as a result of a reduction in ISP duration, no benefit from a reduction in operating reserves would be attributable to the change in ISP duration.

Stakeholders are asked to consider and document:

- **3.1.1. Impact on actions undertaken by BRPs and balancing actions undertaken by TSO.** The survey assumes here that, in the status quo, BRPs submit physical notifications and balancing bids and offers to the TSO, leading to balancing actions by the TSO post gate closure. Subsequent to a reduction in the ISP duration, the survey envisages that there will be scope for BRPs to use the information on forecast generation at ISP duration granularity and take an increased number of trading actions in the intraday market (pre-gate closure) or physical actions (also pre-gate closure) to reduce its imbalance position in each ISP. This would in turn reduce the need for TSO balancing actions. At the same time there could be a shift between manual and automatic reserves leading to a cost reduction (or increase) resulting from the dimensioning methodology.

Stakeholders are asked to quantify:

- The incremental annual volume of pre-gate closure trading actions with finer granularity BRPs would themselves undertake on the intraday market or through pre-gate closure physical actions with finer granularity (in MWh) instead of the TSO (assuming no change in Gate Closure Time, as discussed in section 1.2.1); and
- The average price difference between the price (or cost) achieved by the BRP when taking actions at a finer granularity on the intraday market relative to the balancing price achieved by the TSO (in EUR or local currency/MWh).

The survey defines balancing actions of the TSOs as all actions needed to ensure the equilibrium between load and generation. Therefore, ramping obligations for BRPs or other post gate closure adjustments of generation by TSOs should be also taken into account in addition to the activation of operating reserves and other balancing bids.

The survey focuses on impacts on the intraday market. If stakeholders are of the view that effects could also materialise in the day-ahead markets, they should flag and explain this in the comments box.

- **3.1.2. Impact on capacity withheld by the BRP and reserves held by the TSO.** The survey assumes here that in the status quo, TSOs may hold reserve to be activated post gate closure to manage system balance. Subsequent to a reduction in ISP duration, BRPs may instead withhold more capacity in the relevant market area (i.e. deliberately withhold it from forward markets) in order to allow for it to be sold on the intraday market with finer granularity or used for physical actions with finer granularity in the period leading up to gate closure. This may allow TSOs to hold less reserve capacity. In addition, structural or deterministic imbalances related to BRP ramping at the breakpoint between ISPs may be reduced due to a reduction in ISP duration, potentially reducing the reserve capacity held by the TSO. Stakeholders are asked to provide their view on

  - the volume of such incremental BRP capacity with-holdings (MW);
  - the average reduction in TSO reserve capacity across the year (in MW); and
  - the difference in average cost of with-holding capacity as a BRP within individual portfolios relative to reserve procurement by the TSO (in EUR or local currency/MW).

- **3.1.3. Cross-border effect.** This question envisages the incremental benefit from harmonising the ISP duration and therefore the granularity of intraday markets across border. This question should be ignored if cross-border ISPs are already harmonised today (even if both ISPs are expected to reduce in the planning cases).
  - The stakeholders are asked to consider here whether, if the BRPs could buy cross-border for the purpose of intraday trading actions, they would expect a further price discount to be achieved relative to the cost of trading only in the relevant intraday market? This discount should be quantified in EUR or local currency/MWh.

    This question assumes that only a price effect is observed. If stakeholders consider that harmonisation could have an impact on volume (i.e. wider increase in liquidity from cross-border harmonisation), this should be documented in the comments section.

    The survey does not separately consider a cross-border effect for TSOs. This is based on the consideration that in the status quo TSOs are already able to trade cross-border for balancing purposes. Stakeholders should confirm whether they share this view in the "comments" section of question 3.1.3, and if not provide an estimate for the associated benefit.
  - Equally, stakeholders are invited to consider any potential reduction in the cost of with-holding capacity for the BRPs should they be able to with-hold capacity on a cross-border basis, rather than domestically (assuming BRPs have access to capacity cross-border). This potential cost saving should be quantified in EUR or local currency/MW of reserve capacity.

- **3.1.4. Impact on prices.** This section envisages the potential impact on balancing, imbalance and wholesale prices of the transfer of balancing actions from TSOs to intraday trading and physical actions by BRPs due to the scheduling and trading with finer granularity of the BRPs.

  In particular, stakeholders are asked to consider whether:

- The capacity freed-up from TSO holding less reserves (see 3.1.2) would participate in the wholesale market and result in a change in the wholesale price. If relevant, the yearly average reduction in wholesale prices should be specified (in EUR or local currency/MWh).
- The reduction in volumes of balancing actions taken by the TSO (see 3.1.1) would result in a change in balancing prices, and therefore on imbalance settlement prices[20]? If relevant, the yearly average reduction in balancing and imbalance settlement prices should be specified (in EUR or local currency/MWh).

- **3.1.5. Impact on entry of BSPs.** In this question, the reduction in ISP is expected to lead to shorter products being available on the balancing mechanism and on the intraday market. Stakeholders are asked to consider whether this could allow more technologies to participate in these markets – for instance, Demand-Side-Response capacity that currently finds it difficult to commit to half-hourly offers could potentially make quarter-hourly offers on the balancing market. Should this be the case, stakeholders should consider the expected effect on wholesale and balancing prices in the market. Stakeholders are asked to quantify:
  - The total volume of new BSP capacity (in MW);
  - The impact on the average yearly balancing prices (in EUR or local currency/MWh);
  - The impact on the average yearly intraday price (in EUR or local currency/MWh); and
  - The yearly volume of balancing actions (in MWh).

  This question assumes that participation in the balancing mechanism today is conditional on the ability to adjust capacity upwards or downwards for the entire duration of an ISP (even if in reality capacity can be required by the TSO to adjust upwards or downwards for a subset of that period). Comments in this assumption should be included the answers to the survey.

- **3.1.6. Further impact on balancing.** Stakeholders are asked to consider here potential further benefits due to the change in ISP duration affecting stakeholders' efforts to be balanced physically, with the benefit being quantified in MWh of reduced balancing volumes and associated EUR or local currency value.

[20] Stakeholders should consider reductions as well as increases in imbalance prices, and report the expected average impact on imbalance prices.

- **3.1.7. "Comments"** enables stakeholders to identify other benefits or a different approach to quantify the benefits discussed above.

3.2.2 Increased secondary trading volumes

Section 3.2 of the survey focuses on benefits from increased secondary trading volumes subsequent to a change in ISP duration. To the extent that stakeholders take the view that traded volumes or the number of trades would decline as a result of dis-aggregation of traded products into shorter duration products, they should provide the net effect on liquidity in this section and indicate in the comments how they have arrived at the net result.

Sections 3.2.1 and 3.2.2 serve to break down the potential savings, following the rationale and assumptions described below. Stakeholders are invited to comment on those assumptions in the survey. If relevant, an alternative assessment of benefits can be provided in the "other" section. In particular, this section focuses on impacts on intraday markets, and assumes few changes arise on the day-ahead market. Stakeholders that do not share this view are welcome to comment and provide further information in the Comments boxes.

This section covers among others the market impact of the changes in balancing actions discussed in section 3.1. Stakeholder should maintain consistency in their answers to both sections.

- **3.2.1. Increased intraday liquidity as a result of BRP actions.** As discussed above, a reduction in ISP duration is expected to lead BRPs to be less in imbalance after the gate closure time by undertaking trading actions with finer granularity on intraday markets. First focusing on the impact of a shorter ISP on the relevant market area only (as opposed to impacts related to neighbouring market areas), stakeholders are asked to:
  - Report here the expected increase in volumes bought and volumes sold by BRPs per year (in MWh), consistently with the expected volume of trading actions by BRPs assumed in question 3.1.1.;
  - Provide their view on the reduction in the bid-ask spread on the intraday market due to this increase in liquidity, in EUR or local currency/MWh; and
  - Provide their view on the impact on net trading fees paid to power exchanges or any other facilitator, in EUR or local currency.

  Stakeholders are then asked to set out separately any further estimated impact on prices (in EUR or local currency/MWh) should BRPs be able to trade shorter duration ISP products cross-border. Note that stakeholders should assume here a fully functional target model with coupled intraday markets.

- **3.2.2. Increased intraday liquidity as a result of greater uniformity of information.** Stakeholders are invited to consider here whether trading would become more simple (uniform ISP periods and product durations across markets), and whether the resulting reduction in transactional effort could be expected to lead to increased liquidity. If relevant, stakeholders are asked to quantify separately:
  - the expected change in volumes bought and sold per year (in MWh) – these volumes are expected to cover
    - volumes bought and sold by BRPs, consistently with the expected volume of trading actions by BRPs assumed in question 3.1.1.; and
    - potential wider increases in volumes traded by other stakeholders, especially cross-border, thanks to the harmonisation of ISP duration;
  - the reduction in the bid-ask spread on the intraday market due to this increase in liquidity, in EUR or local currency/MWh; and
  - the effect on net trading fees paid to power exchanges or any other facilitator, in EUR or local currency.

Section 3.2.3 enables stakeholders to identify other benefits or a different approach to quantify the benefits discussed above.

3.2.3 Improved investment outcomes

Section 3.3. of the survey focuses on benefits from improved investment outcomes subsequent to a change in ISP duration.

Sections 3.3.1 and 3.3.2 serve to break down the potential savings, following the rationale and assumptions described below. Stakeholders are invited to comment on those assumptions in the survey. If relevant, an alternative assessment of benefits can be provided in the "other" section.

These questions consider the drivers for investment in new capacity. In the status quo, it is assumed that flexible capacity receives price signals for investment from the combination of reserve, balancing and wholesale prices, subject to the plant's ability to participate in each market. Stakeholders are invited to consider whether,

- 3.3.1. All else equal, a transfer of revenues from the balancing or reserve markets to the wholesale market would lead to more efficient investment outcomes (e.g. due to more transparency and ability to forecast wholesale prices over balancing prices)?
- 3.3.2. A move to shorter ISP could remove barriers to participation in some markets for some capacity types and therefore result in more efficient investment outcomes (e.g. DSR capacity ability to participate in

balancing markets for a 15-minute duration but not 30 minutes, as discussed in 3.2.1 above?

These considerations should focus on the incremental impact of a change in ISP duration, absent any changes to other potential drivers of investment relative to the status quo (e.g. in particular in relation to price caps and scarcity pricing).

These effects should be quantified as:

- Impact on the volume of new investment (in MW);
- Estimated difference in cost (in EUR or local currency/MW) between the new resource and that which would have been installed otherwise had the barriers remained in place.

Stakeholders should ensure that they maintain consistency between the assumptions they make here the answers provided when assessing benefits 3.1 and 3.2.

Section 3.3.3 enables stakeholders to identify other benefits or a different approach to quantify the benefits discussed above.

3.2.4 Reduced dispatch costs

Section 3.4. of the survey focuses on benefits from improved power plant dispatch subsequent to a change in ISP duration.

This section focuses on the impact on dispatch costs (as opposed to market prices) of the changes in balancing actions discussed in section 3.1. Stakeholders should maintain consistency regarding underlying assumptions in their answers to both sections.

In this section, stakeholders are asked to consider the impact on dispatch cost (e.g. fuel cost and carbon costs) across the system from increased trading with higher granularity of schedules for BRPs and entry of new BSPs.

For example, where additional DSR capacity is able to participate as a BSP provider, it could lead to substitution of an OCGT in favour of DSR for a share of downward adjustments on the balancing mechanism. Stakeholders would therefore be asked to consider the balancing volumes for which substitution is achieved (in MWh) and the average cost saving (in EUR or local currency/MWh) arising from this, including:

- Fuel costs;
- Carbon costs;
- Opportunity costs; and
- Other OPEX.

Equally, stakeholders are invited to provide information on changes in dispatch costs from substituting balancing actions by the TSO via the balancing mechanism with trading actions with a finer granularity from BRPs via the intraday market or physical actions pre gate closure.

Finally, stakeholders are invited to consider any cross-border effects and opportunity for reduction in dispatch costs from the harmonisation of ISP durations cross-border. Stakeholders should separate out:

- Their view on the volume of dispatch (in MWh, 3.4.2) which might benefit from cross-border trading with finer granularity; and
- Their view on the associated reduction in average price on the relevant intraday market (in € or local currency/MWh, 3.4.2).

Stakeholders should note that they should consider here the incremental benefit from ISP duration harmonisation relative to the harmonisation embedded in the implementation of the target model (ie intraday market coupling).

3.2.5 Frequency quality

Section 3.5 of the survey focuses on the effect of a reduction in ISP duration on frequency quality. It is possible that reducing ISP duration improves frequency quality, by reducing the number and extent of frequency excursions.

In this section TSOs are asked to provide their estimates as to the effect of the change to ISP duration on:

- the change in the number of frequency excursions per year (3.5.2); and
- the value of the improvement to frequency quality (in Euro or local currency, 3.5.2).

It may be difficult for stakeholders to provide a single figure as to the change to frequency quality as a result of the reduction in ISP duration. Therefore, stakeholders are encouraged to use the comment box to provide further information as to the effect on frequency.

When estimating the value of the change to frequency quality, stakeholders could estimate this as the avoided cost to the TSO (not taken into account elsewhere in the survey) in managing frequency or it could be based on an estimate of the value of frequency quality to end users. Stakeholders are asked to use the comment box to specify the approach used and provide any supporting evidence.

3.2.6 Other monetary benefits

This section is available for stakeholders who have identified benefits that do not fall in any of the categories discussed previously. In particular, stakeholders should report here any benefits linked to the objectives of the NC not captured in the list above[21].

Benefits addressed here should be quantified and documented in a similar manner to that used in previous sections.

3.2.7 Participation of renewables

Section 3.7. of the survey focuses on benefits in terms of participation of renewables. This is a non-monetary benefit which will be assessed based on stakeholders' qualitative replies to the survey. In their responses to 3.7.1, stakeholders should consider in particular where the reduction in ISP duration may:

- make it easier for any particular renewable energy sources to participate as Balancing Service Providers – this might be the case for instance where RES are able to commit to volumes on the shorter ISP duration where they might not have been able to for the longer ISP duration[22] (but assuming no change in Gate Closure Time); and
- increase the exposure of renewable energy sources to imbalance prices.

Stakeholders should note that they should consider the incremental impact of the change in ISP duration on participation of renewables, holding all else equal. In particular stakeholders should consider that current renewable support mechanisms continue to prevail in the future, unless changes have already been agreed on at the time of the CBA.

Other factors facilitating the participation of renewables should be addressed in section 3.7.2.

3.2.8 Ensuring operational security

Section 3.8 of the survey focuses on benefits in terms of operational security of the power system. This is a non-monetary benefit which will be assessed based on stakeholders' qualitative replies to the survey. In their responses to 3.8.2., stakeholders should comment on the argument that cross-border balancing

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21 Although the CBA sits outside the NC, the CBA methodology uses the same objectives as in the NC.

22 As previously, this assumes that participation in the balancing mechanism requires the ability to commit to adjusting upwards or downwards for the whole duration of the ISP even if the TSO can then require adjustments on shorter time periods.

actions are currently restricted, for instance because BSPs in long ISP country cannot participate in countries with short ISPs or because of restrictions to TSOs' ability to trade cross-border for balancing purposes. Stakeholders should discuss whether they consider this to contribute to the security of supply in the electric system and whether enhanced cross-border balancing via ISP harmonisation would contribute to improve security of supply.

3.2.9 Pass/fail criteria

The CBA will include a qualitative assessment of changes to the ISP duration under a number of pass-fail criteria, which the proposed changes will have to pass to be considered further.

Stakeholders are invited to use section 3.9 of the survey to provide views on whether they expect the proposed changes would fail the assessment under the following criteria:

- Security of supply (ensuring operational security and the ability of TSOs and BRPs to fulfil their obligations);
- Market design (facilitating demand side participation, facilitating renewable participation, avoiding barriers to entry, non-discrimination and transparency in balancing markets, and ensuring fair, objective and transparent and market based procurement of balancing services); and
- Ability to implement (technical feasibility).

3.2.10 Other comments

Finally, a comments box is provided in section 3.10 of the questionnaire to enable stakeholders to provide their general view on the factors in the operating and market environment that would make changing the ISP duration effective and useful and the wider issues that are at stake or need addressing to ensure the benefits discussed in earlier sections will arise.

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