entsog

european network
of transmission system operators
for gas

Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas

MARCH 2017

Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas

ENTSOG welcomes the feedback of market participants on the Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas **('TAR NC IDoc')**.

Please send your comments by **30 June 2017 at TAR-NC@entsog.eu** indicating: (1) the relevant page of TAR NC IDoc; (2) explanation of your concern; and (3) your proposal for amending the text of TAR NC IDoc.

ENTSOG will review this TAR NC IDoc – taking the received feedback into account – and will publish an updated version of the TAR NC IDoc before the second TAR NC Implementation Workshop planned for October 2017.

Table of Contents

PART 2

Disclaimer

The European Network of Transmission System Operators for Gas ('ENTSOG')[1] has developed this Implementation Document ('IDoc') for the Network Code on harmonised transmission tariff structures for gas ('TAR NC').

The IDoc is non-binding, prepared for information and illustrative purposes, and offers a set of examples and possible solutions for implementing the TAR NC. The examples used in the IDoc for any given Member State **('MS')** reflect the situation as of the date of the IDoc publication, and may change in the future as an outcome of the national consultation processes foreseen in the TAR NC.

The TAR NC applies directly in all MSs. For the avoidance of doubt, the IDoc is not part of the TAR NC; ENTSOG provides the IDoc for information purposes only, without accepting any legal responsibility for its content, which does not give rise to any rights or obligations whatsoever. If in any respect the IDoc is not consistent with the TAR NC, then the TAR NC prevails.

ENTSOG has shared the draft IDoc with the Agency for the Cooperation of Energy Regulators **('ACER')** and national regulatory authorities **('NRA')**, has engaged in discussions, and considered feedback. The experts providing feedback to this document in no way commit their institutions. The feedback received from ACER and NRAs experts has been largely taken on board. ACER and NRAs experts providing feedback to this document in no way commit their institutions, and the document was not subject to their approval or endorsement. The European Commission **('EC')** was informed of the preparation of the IDoc.

1) See ENTSOG's website: www.entsog.eu/members. As of March 2017, ENTSOG comprises 45 TSO Members and 2 Associated Partners from 26 European countries, and also has 4 Observers from EU affiliate countries: FYROM, Norway, Switzerland and Ukraine.

Introduction

Image courtesy of National Grid

TAR NC – Network Code on Harmonised Transmission Tariff Structures for Gas

The TAR NC has recently undergone formal review ('Comitology Procedure') according to Article 5a(1) to (4) and Article 7 of Council Decision 1999/468/EC[1], as envisaged by Article 28(2) of Regulation (EC) No 715/2009 ('Gas Regulation')[2),3)]. The Official Journal of the European Union ('EU') published the TAR NC on 17 March 2017[4], and it will enter into force 20 days later on 6 April 2017.

TAR NC – A NEW GAS NETWORK CODE

A network code **('NC')** is a set of common EU-wide rules in the form of an EU regulation established in accordance with the process contemplated by Article 6 of the Gas Regulation for a given subject matter, as indicated by Article 8(6). Article 6(11) clarifies that NCs supplement the Gas Regulation and *'amend… [its] non-essential elements'*.

The TAR NC is the fourth network code in the gas sector, following the NCs on capacity allocation mechanisms **('CAM NC')**[5], gas balancing of transmission networks **('BAL NC')**[6], and interoperability and data exchange rules **('INT NC')**[7]. The CAM NC **('Old CAM NC')** has been subject to amendment in parallel to the development of the TAR NC. The Comitology Procedure has been finalised, repealing the Old CAM NC. The Official Journal of the EU published the revised version **('Amended CAM NC')** on 17 March 2017[8], and it will enter into force 20 days later on 6 April 2017. For the avoidance of doubt, if the IDoc refers to the CAM NC without specifying the Old CAM NC or the Amended CAM NC, the one in force is the relevant version.

1) Council Decision 1999/468/EC of 28 June 1999 laying down the procedures for the exercise of implementing powers conferred on the European Commission as amended by Council Decision 2006/512/EC of 17 July 2006 (OJ L 200, 22.7.2006, p. 11).

2) Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (OJ L 211, 14.8.2009, p. 36).

3) Currently the Gas Regulation provides for the application of the regulatory procedure with scrutiny. In case of the change of the applicable procedure due to the Lisbon Treaty, the new procedure will apply accordingly.

4) Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (OJ L 72, 17.3.2017, p. 29).

5) Commission Regulation (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009 of the European Parliament and of the Council (OJ L 273, 15.10.2013, p. 5).

6) Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks (OJ L 91, 27.3.2014, p. 15).

7) Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules (OJ L 113, 1.5.2015, p. 13).

8) Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013 (OJ L 72, 17.3.2017, p. 1).

Since the TAR NC is an EU regulation, it applies directly in all MSs. Although not explicitly stated in its recitals, the TAR NC supplements and forms an integral part of the Gas Regulation. The TAR NC further harmonises rules as envisaged in Article 13 of the Gas Regulation, as well as the respective tariff transparency provisions according to Chapter 3 of Annex I to the Gas Regulation **('Transparency Guidelines')**.

Given their simultaneous publication, the TAR NC and the Amended CAM NC will enter into force on the same date, 6 April 2017. On that date the Amended CAM NC repeals the Old CAM NC, including the EU-wide tariff rules of Article 26; the rules remain in force until then. The new EU-wide tariff rules will be in the TAR NC.

INTERACTION WITH OTHER NETWORK CODES AND GUIDELINES

As indicated above, Article 8(6) of the Gas Regulation identifies possible areas for the development of NCs, most of which are now covered by existing NCs. The TAR NC covers 'rules regarding harmonised transmission tariff structures' in point (k).

All NCs constitute and form integral parts of the Gas Regulation; its consistent and coherent implementation requires due consideration of the interactions between the Gas Regulation and any given NC, and between NCs. The TAR NC interacts with other NCs and Guidelines[1] as follows:

- **Amended CAM NC:** certain rules of the TAR NC refer specifically to interconnection points **('IP')**, subject to the Amended CAM NC. The listed rules in the TAR NC address tariff-related issues of the Amended CAM NC: Chapter III 'Reserve prices', Chapter V 'Pricing of bundled capacity and capacity at virtual interconnection points **('VIP')**', Chapter VI 'Clearing and payable price', Article 28 on discounts, multipliers and seasonal factors from Chapter VII 'Consultation requirements', Article 32(2)–(3) on publication of certain tariff information on ENTSOG's Transparency Platform **('TP')** from Chapter VIII 'Publication requirements' and Chapter IX 'Incremental capacity'. The Amended CAM NC governs the process for offering incremental capacity, while the TAR NC sets out the tariff principles for incremental capacity.
- **Transparency Guidelines:** Chapter VIII 'Publication requirements' sets out tariff transparency obligations that further elaborate and harmonise the tariff transparency obligations in the Transparency Guidelines.
- **BAL NC:** the TAR NC treats the balancing activity of a TSO as a 'third' service category independent of transmission and non-transmission services. Balancing costs receive separate treatment given the application of a neutrality mechanism under the BAL NC.
- **INT NC:** the TAR NC incorporates all the definitions introduced by the INT NC.
- Chapter 2.2 of Annex I to the Gas Regulation **('CMP Guidelines')**: although the Gas Regulation defines physical and contractual congestion, there is an indirect link between the TAR NC and the CMP Guidelines. The CMP Guidelines stipulate the detailed measures for solving contractual congestion, which can affect the TSO's revenue recovery, as when implementing an oversubscription and buy-back procedure.

As for definitions, the TAR NC incorporates those employed in Directive 2009/73/EC **('Gas Directive')**[2], the Gas Regulation, and other NCs: the Amended CAM NC, the BAL NC and the INT NC. For ease of reference, ENTSOG has published a comprehensive list of all such definitions[3].

---

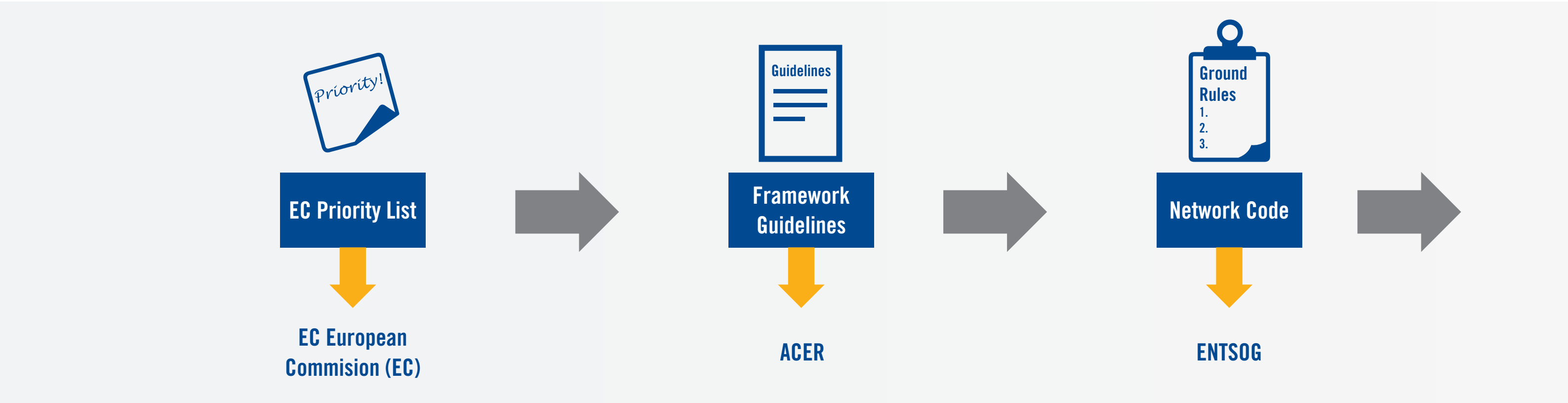
1) For further information on the EC Guidelines, see Article 23 of the Gas Regulation.

2) Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (OJ L 211, 14.8.2009, p. 94).

3) See 'Glossary of definitions': www.entsog.eu/publications/glossary-of-definitions#GLOSSARY-OF-DEFINITIONS.

NETWORK CODE ESTABLISHMENT PROCESS

Article 6 of the Gas Regulation sets out the process for creating a NC, which involves ENTSOG, ACER, the EC and all other market participants. Figure 1 illustrates the stages of the NC establishment process.



The NC establishment process involves the following steps:

- After consulting with market participants the EC establishes an annual priority list, which may call for the development of framework guidelines **('FG')** or NCs for specific topics.

  There was no priority list in 2011, as the Gas Regulation rules only applied as from 3 March 2011. However, in 2010 the 17th Madrid Forum already *'welcomed ERGEG's intention to continue its work on… tariff structures, with the goal of preparing input to framework guidelines on transmission tariff structures…'* [1), 2)].

- The EC requests ACER to prepare the non-binding FG within *'a reasonable'* time period *'not exceeding six months'*, but which the EC *'may extend'*.

  The TAR NC followed the TAR FG preparation, which took 17 months[3)]. The EC's invitation did not originate in the annual priority list but in discussions within the Trilateral Planning Group every two months[4)]. ACER has organised two public consultations, two workshops and two 'open house' events to engage with stakeholders when preparing the TAR FG. ACER has also published a Justification Document elaborating upon the TAR FG.[5)]

- The EC asks ENTSOG to prepare a NC in line with the relevant FG within *'a reasonable'* time period *'not exceeding twelve months'*. In contrast to the time period for developing ACER's FG, the Gas Regulation does not contemplate prolonging the time period for ENTSOG's development of the NC.

  ENTSOG took 12 months to prepare the TAR NC[6)].

- ENTSOG develops the draft NC for submission to ACER[7)]. Within the NC development process, ENTSOG organises a number of public consultations on the drafts of a NC: stakeholder joint working sessions before drafting the legal text, consultation on the initial draft NC, and a stakeholder support process with respect to the refined draft NC. As envisaged by Article 10(3) of the Gas Regulation, ENTSOG has supplemented all drafts of the NC with supporting material explaining how it took into account stakeholder comments[8)].

  For the TAR NC, ENTSOG has organised three public consultations, five stakeholder joint working sessions and three workshops to engage with stakeholders and solicit their views. With each version of the draft TAR NC, ENTSOG published three additional documents explaining the choices made in the draft legal text[9)].

---

1) ERGEG – European Regulators' Group for Electricity and Gas, a 'forerunner' to ACER: www.ceer.eu/portal/page/portal/EER_HOME/EER_ABOUT/Tab

2) See conclusions of the 17th Meeting of the European Gas Regulatory Forum of 14–15 January 2010: https://ec.europa.eu/energy/sites/ener/files/documents/meeting_017.zip

3) The EC invitation for ACER to start the procedure for developing the TAR FG is dated 29 June 2012: www.acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Documents/FG_TAR_Invitation.pdf
The final TAR FG was published on 29 November 2013: www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/Framework%20Guidelines%20on%20Harmonised%20Gas%20Transmission%20Tariff%20Structures.pdf

4) The Trilateral Planning Group Material was publicly available in 2011–2012.

5) See ACER website for 'Harmonised transmission tariff structures for gas': www.acer.europa.eu/en/gas/Framework%20guidelines_and_network%20codes/Pages/Harmonised-transmission-tariff-structures.aspx

6) The EC invitation for ENTSOG to draft the TAR NC is dated 19 December 2013: http://entsog.eu/public/uploads/files/publications/Tariffs/2013/20131217%20Invitation%20ENTSOG%20draft%20NC%20TAR.pdf

7) The TAR NC developed by ENTSOG was submitted to ACER on 26 December 2014: http://entsog.eu/public/uploads/files/publications/Tariffs/2014/TAR0450_141226_TAR%20NC_Final.pdf

8) See Article 28 'Code development' of ENTSOG's Rules of Procedure: http://www.entsog.eu/public/uploads/files/publications/Statutes/2012/ENTSOG_RoP_GA_2012_03_06.pdf

9) See Annex R 'Versions of ENTSOG's TAR NC and additional material' and ENTSOG's website for all documents related to public consultations: http://entsog.eu/publications/tariffs#All

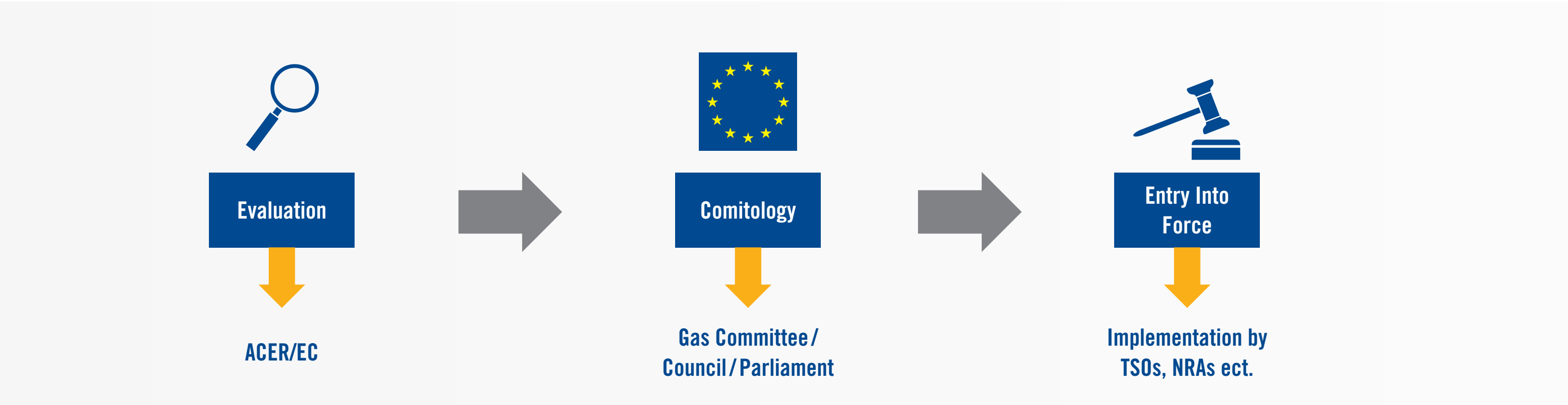


Figure 1: NC establishment process

- ACER provides a reasoned opinion on the draft NC submitted by ENTSOG within a time period of no more than three months.

  The TAR NC reasoned opinion preparation took three months[1].

- ENTSOG may choose to amend the draft NC *'in the light of'* ACER's reasoned opinion and re-submit it to ACER. The Gas Regulation is silent on the duration of the potential interaction between ENTSOG and ACER.

  As with all previous NCs, ENTSOG has re-submitted the redrafted TAR NC to ACER[2] along with a document explaining the choices made in the legal text[3]. ENTSOG, ACER and the EC held a number of trilateral meetings to discuss the next steps.

- Once ACER *'is satisfied'* that the NC is *'in line'* with the FG, ACER may choose to recommend the NC for adoption by the EC.

  ACER did not secure a favourable opinion of the Board of Regulators for the re-submitted TAR NC, so it did not provide such a recommendation[4].

- The Gas Regulation envisages other ways forward in the absence of ACER's recommendation.

  At the 28th Madrid Forum the EC announced its decision to 'take over' the few remaining steps for the finalisation of the TAR NC. The Forum noted *'the Commission's intention – taking due account of the views of ACER, ENTSOG and stakeholders – to launch the formal legislative procedure still in Q1 2016'*[5].

- The Comitology Procedure involves the Gas Committee (Committee on the implementation of common rules on the transport, distribution, supply and storage of natural gas), the European Parliament and the Council. The EC adopts the NC at the end of the Comitology Procedure[6].

  For the TAR NC, the relevant comitology documents are available in the Comitology Register, including the draft legal texts of the TAR NC, the associated impact assessment and the Gas Committee's voting sheet and the summary record[7]. The final TAR NC is published in the Official Journal of the EU[8].

1) The reasoned opinion of ACER was published on 26 March 2015: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2002-2015.pdf
2) The TAR NC re-drafted by ENTSOG was submitted to ACER on 31 July 2015: http://entsog.eu/public/uploads/files/publications/Tariffs/2015/TAR0500_150731_TAR-NC%20for%20Re-Submission_ACER.pdf
3) See Annex U 'Versions of ENTSOG's TAR NC and additional material'.
4) No official announcement on ACER's website. See conclusions of the 28th Meeting of the European Gas Regulatory Forum of 14–15 October 2015 ('The Forum takes note that ACER is not providing a Recommendation on the Network Code regarding harmonised transmission tariff structures for gas […]'.): https://ec.europa.eu/energy/sites/ener/files/documents/28th%20MF%20Conclusions%20V8.pdf
5) See conclusions of the 28th Meeting of the European Gas Regulatory Forum of 14–15 October 2015: https://ec.europa.eu/energy/sites/ener/files/documents/28th%20MF%20Conclusions%20V8.pdf
6) For the information on the TAR NC, see the beginning of this section and 'TAR NC – a new gas network code'.
7) See the dossier number 'CMTD(2016)0778' in the Comitology Register: http://ec.europa.eu/transparency/regcomitology/index.cfm?do=search.result
8) OJ L 72, 17.3.2017, p. 29.

TAR NC IMPLEMENTATION DOCUMENT

Nature of this document

The disclaimer at the beginning of the IDoc explains its nature and its aims.

Structure

The IDoc has three Parts:

- **Part 1: 'Overview of the TAR NC requirements':** this Part addresses 'what' the TAR NC contains, offering an overview of the TAR NC requirements Article-by-Article. Chapters within Part 1 of the IDoc follow the structure of the TAR NC. Each Chapter starts by indicating its scope and application date **('AD')**, followed by a high-level overview. The ensuing body of each Chapter follows the order of the TAR NC Articles.
- **Part 2: 'Indicative Timeline for the TAR NC implementation':** this Part deals with 'when', elaborating the indicative timeline for implementing the TAR NC, and identifying the parties responsible for complying with different obligations. Chapters within Part 2 of the IDoc include:

  1) a table summarising all the TAR NC obligations for the TSOs, NRAs, ENTSOG, ACER and the EC;

  2) a general implementation; timeline applicable for all MSs; and

  3) different timelines depending on the tariff period applied in a given MS.
- **Annexes:** this Part includes examples and calculations related to some substantive points described in Part 1.

Next steps

The 29th Madrid Forum invited ENTSOG and ACER *'to support and monitor the implementation' of the TAR NC 'and report back to the Forum'*[1]. The IDoc is part of ENTSOG's response to this invitation.

We plan to hold a TAR NC Implementation Workshop on 29 March 2017, to inform the market about implementing the TAR NC. We have chosen this date considering its proximity to the TAR NC's entry into force on 6 April 2017 offering market participants timely notice of the implementation challenges.

1) See conclusions of the 29th Meeting of the European Gas Regulatory Forum of 6–7 October 2016: https://ec.europa.eu/energy/sites/ener/files/documents/29th_mf_conclusions_adopted.pdf

Part 1

Overview of the TAR NC Requirements

This Part of the IDoc follows the structure of the TAR NC. Chapters and their Articles follow the order of their appearance in the TAR NC. Each Chapter starts with a summary to provide the reader a full picture. The details of some Articles are outlined in respective Annexes.

Image courtesy of GAZ-SYSTEM

Citations and Recitals

Several citations and recitals precede the Articles of the TAR NC. The citations are the two paragraphs starting with ‘having regard to…’; the recitals are the 12 ‘whereas’ paragraphs.

CITATIONS

Citations describe the legal framework for the TAR NC, setting the scene for ‘where it comes from’. The first citation refers to the primary legislation – Treaty on the Functioning of the EU[1)], while the second citation refers to the secondary legislation – the Gas Regulation. The second one also mentions Article 6(11) of the Gas Regulation, which established the procedure for adopting a NC.

RECITALS

Although the TAR NC is *‘binding in its entirety’*, the recitals are not legally binding in isolation. They need to be read in conjunction with the respective Articles, as they provide the background for the rules set out in the Articles. In particular, the TAR NC recitals are linked to the following rules: transparency requirements, consultation on the proposed reference price methodology **(‘RPM’)**, the level of discounts at certain points on the system, the approach towards high-transit systems and interconnectors, and so forth.

Apart from the background for the specific rules, recitals also serve the following purposes:

- Recitals (1) and (10) mention the high-level objectives of the TAR NC, such as contributing to market integration, enhancing security of supply, promoting interconnection between gas networks and avoiding foreclosure of downstream supply markets.
- Recital (11) provides some guidance for implementing the TAR NC, encouraging both NRAs and TSOs to adopt *‘best practices and endeavours to harmonise processes for the implementation’* of the TAR NC; ACER and NRAs should *‘ensure’* that the TAR NC rules *‘are implemented across the Union in the most effective way’*.
- In conjunction with Article 6(11) of the Gas Regulation mentioned in the second citation, recital (12) recalls the Comitology Procedure for adopting the TAR NC, which includes the step of securing the opinion of the Committee established per Article 51 of the Gas Directive.

1) Consolidated version: OJ C 326, 26.10.2012, p. 47–390.

Chapter I: General Provisions

Chapter I 'General Provisions' of the TAR NC is structured as follows: Articles 1 to 3 address 'general concepts' of broad application: subject matter, scope and definitions. Article 4 sets out the 'services and tariffs' addressed in the TAR NC. Article 5 elaborates on the details of 'cost allocation assessments' that play a role in the periodic consultation.


Image courtesy of Enagás

Summary

Scope: IPs and non-IPs
Application date: entry into force (6 April 2017)

Similar to all the previous NCs, Chapter I deals with subject matter, scope and definitions. This Chapter also includes an overview of different TSO services and their respective tariffs, as well as an Article on cost allocation assessments **('CAA')**.

The **subject matter** of the TAR NC is *'harmonised transmission tariff structures for gas'* – as identified in Article 8(6) of the Gas Regulation.

The **scope** of the TAR NC is not the same for all Chapters. Four out of ten Chapters apply only to IPs, while the rest apply to all entry and exit points. Chapters limited to IPs are:

- Chapter III 'Reserve prices';
- Chapter V 'Pricing of bundled capacity and capacity at VIPs';
- Chapter VI 'Clearing and payable price'; and
- Chapter IX 'Incremental capacity'.

Some Chapters have a broad scope, but contain Articles with a more limited scope:

- Article 28 on NRA consultation on discounts, multipliers and seasonal factors in Chapter VII 'Consultation requirements'; and
- Article 31(2)–(3) on the publication of certain tariff information on ENTSOG's TP in Chapter VIII 'Publication requirements'.

Chapters III, V, VI, IX and Article 28 **may** be applied at non-IPs.

If the NRA has decided to apply the CAM NC at entry-points-from/exit-points-to third countries, then Chapters III, V, VI, IX and Article 28 of the TAR NC apply without the need for an additional decision. The TAR NC leaves this possibility at the national discretion for other points.

The TAR NC incorporates the **definitions** set out in the Gas Regulation, the Gas Directive and from the other network codes.

The definitions of **transmission services and non-transmission services** guide the attribution of TSO revenues. The TSO recovers transmission services revenue from the sale of capacity and from commodity charges, and recovers non-transmission services revenue via separate non-transmission tariffs. Transmission tariffs are capacity-based by default, with two exceptions limited to two types of commodity-based transmission tariffs.

The distinction between transmission services and non-transmission services affects some TAR NC rules. The list above identified Chapters and Articles limited in scope to IPs; they only refer to transmission services. The rest of the TAR NC is mostly about transmission services but also captures some rules for non-transmission services.

CAA aim to identify the degree of cross-subsidisation between intra-system and cross-system use. They outline the methodology for determining the ratio between the revenues recovered from cross-system users and intra-system users.

General Concepts

ARTICLE 1 SUBJECT MATTER

Responsibility: no implications for TSO/NRA responsibility

As indicated by its title, the TAR NC covers 'harmonised transmission tariff structures for gas', one of the areas for developing a NC as stated in Article 8(6)(k) of the Gas Regulation. The 'tariff structures' cover the ways TSOs collect revenues associated with the provision of services at entry and exit points, via capacity- and commodity-based transmission tariffs and non-transmission tariffs. For capacity-based tariffs, the 'tariff structures' cover the methodologies both for calculating the reference price and for deriving specific tariffs based on the reference price.

Article 1 also provides some examples of TAR NC rules: RPM application, consultation requirements, publication requirements and the calculation of reserve prices. The list is not exhaustive.

ARTICLE 2 SCOPE

Responsibility: the NRA may decide to apply the CAM NC at entry-points-from/exit-points-to third countries, in which case the 'limited' scope rules of the TAR NC apply automatically. The 'limited' scope rules may be extended per national decision to: (1) entry-points-from/exit-points-to third countries where the CAM NC does not apply; and (2) non-IPs other than entry-points-from/exit-points-to third countries

Application of the TAR NC at different points on transmission network

The scope of the TAR NC is not homogeneous, as it differs with respect to different types of points. Article 2(1) envisages applying all of the TAR NC rules by default to all the points on the transmission network. However, some of its rules have a 'limited scope' and apply only at IPs, which is the same scope as the CAM NC. So the TAR NC rules in fact split into 'limited scope' rules and 'broader scope' rules as shown in Figure 2.

'Broader scope' rules apply at all points. The application of 'limited scope' rules depends on the type of point: (1) at IPs, such application is 'by default'; (2) at points with third countries where the NRA decides to apply the CAM NC, such application is 'automatic' and does not require additional decision; (3) at other points, such application is possible per national decision. Based on Article 2(1), Figure 3 explains this difference. The red lines stand for the application of the 'broader scope' rules, while the orange lines represent the application of 'limited scope' rules. Figure 3 also shows which connections are explicit (solid lines) in the TAR NC and which ones are based on ENTSOG's assumptions (dashed lines).

The IDoc is written to reflect the reference of IPs and non-IPs as set out in the TAR NC. However, nothing prevents the relevant national authority to extend the 'limited scope' rules to non-IPs. Therefore, the IDoc should be read together with Figure 3.

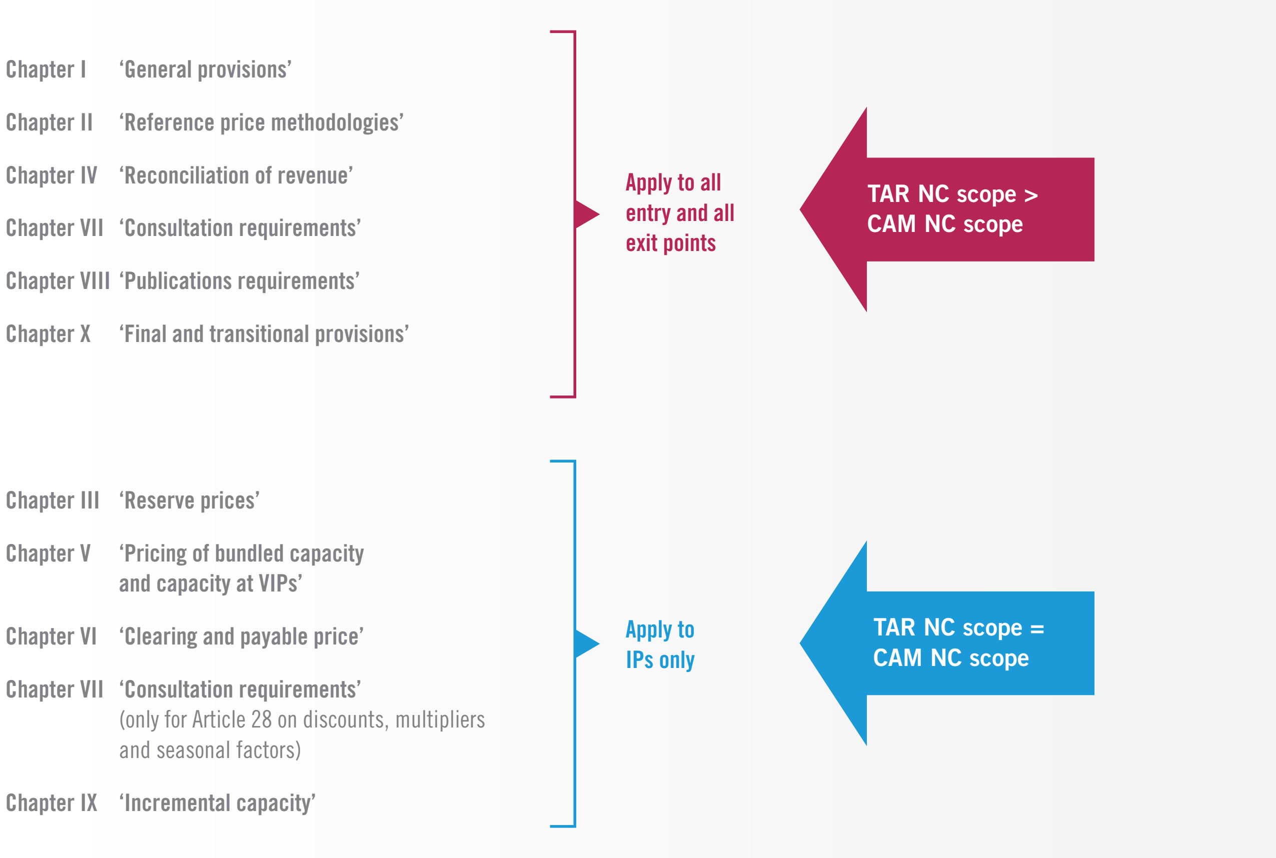


Figure 2: Application of the TAR NC rules at different points on the transmission network

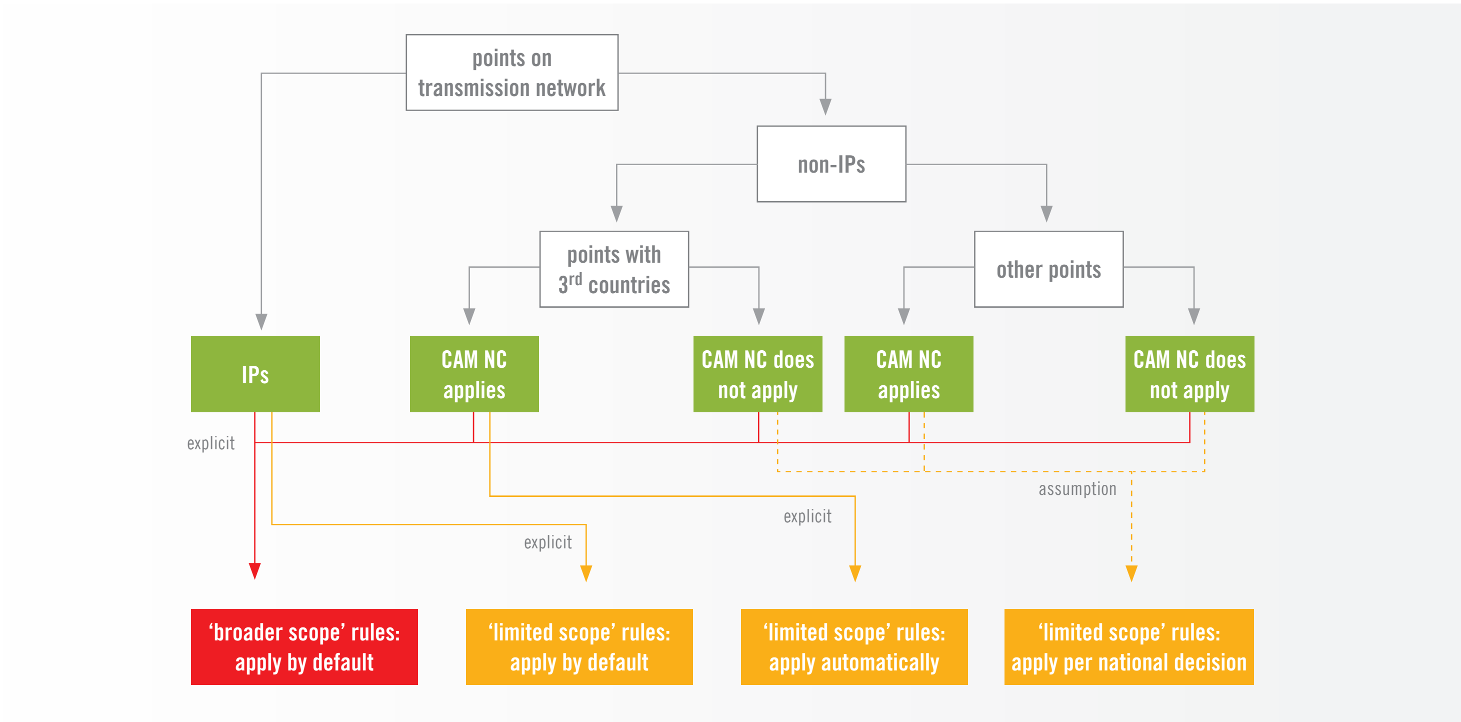


Figure 3: The TAR NC scope at different points of transmission networks

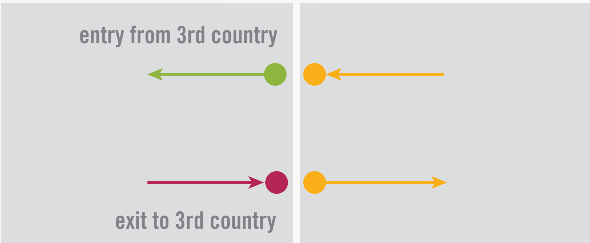
Application of the TAR NC at points with third countries

At entry–points-from/exit-points-to third countries, the applicability of the TAR NC depends on the type of rule involved. Figure 4 shows the following distinction:

- If the rules have a 'broader scope' as described above, then they automatically apply, since entry-points-from/exit-points-to third countries fall under *'all entry points and all exit points of gas transmission networks'* per Article 2(1) of the TAR NC.
- If the rules have 'limited scope' as described above, then they apply only if the NRA has taken a decision to apply the CAM NC at those points. No separate national decision to apply the TAR NC at those points is needed.

Green/Red points

'broader scope' rules apply by default; and limited scope rule apply automatically if NRA desided to apply CAM NC at these points



Yellow points

distinction between Energy Community and other countries

Figure 4: Application of the TAR NC rules at points with third countries

Derogation under Article 49 of the Gas Directive

Article 2(2) specifies that the TAR NC does not apply in MSs that hold a derogation in accordance with Article 49 'Emergent and isolated markets' of the Gas Directive. Article 2(2) echoes Article 30 of the Gas Regulation, which exempts the applicability of the Gas Regulation to MSs for as long as they hold such a derogation. The TAR NC supplements the Gas Regulation, and forms an integral part of it, so if the Gas Regulation does not apply, neither does the TAR NC.

Cyprus, Estonia, Finland, Latvia, Luxembourg and Malta currently have derogations. Article 49 of the Gas Directive mentions Lithuania, but Lithuania did not and does not hold a derogation.

- The TAR NC does not affect Malta and Cyprus as long as they remain isolated markets without a gas transmission system.
- The situations of Estonia, Finland and Latvia might change. Those three MSs currently benefit from derogations, but they may open their natural gas markets in the near future. According to Article 49 of the Gas Directive, the derogation automatically expires as soon as the relevant MS no longer has only one single main external supplier with a market share above 75 %, or as soon as it becomes directly connected to the interconnected system of any MSs other than Estonia, Finland, Latvia and Lithuania.
- Luxembourg holds a derogation according to Article 49(6) of the Gas Directive, which refers to its Article 9 on unbundling of transmission systems and TSOs.

DEFINITIONS

Responsibility: no implications for TSO/NRA responsibility except for specific examples listed below

General[1)]

The TAR NC incorporates the definitions set out in the Gas Directive, the Gas Regulation, the Amended CAM NC, the BAL NC and the INT NC. Therefore, all the definitions from all the existing gas network codes apply for the purposes of the TAR NC. In addition, the TAR NC sets out new definitions.

The Amended CAM NC also cross-references and incorporates the TAR NC definitions.

TSO's revenue and tariffs

Figure 5 illustrates the link between the TSO's allowed/target revenue and different applicable tariffs. An asterisk indicates that Article 3 defines the given term.

Green indicates the allowed/target revenue, which is the sum of the transmission services revenue indicated in grey, and the non-transmission services revenue in yellow.

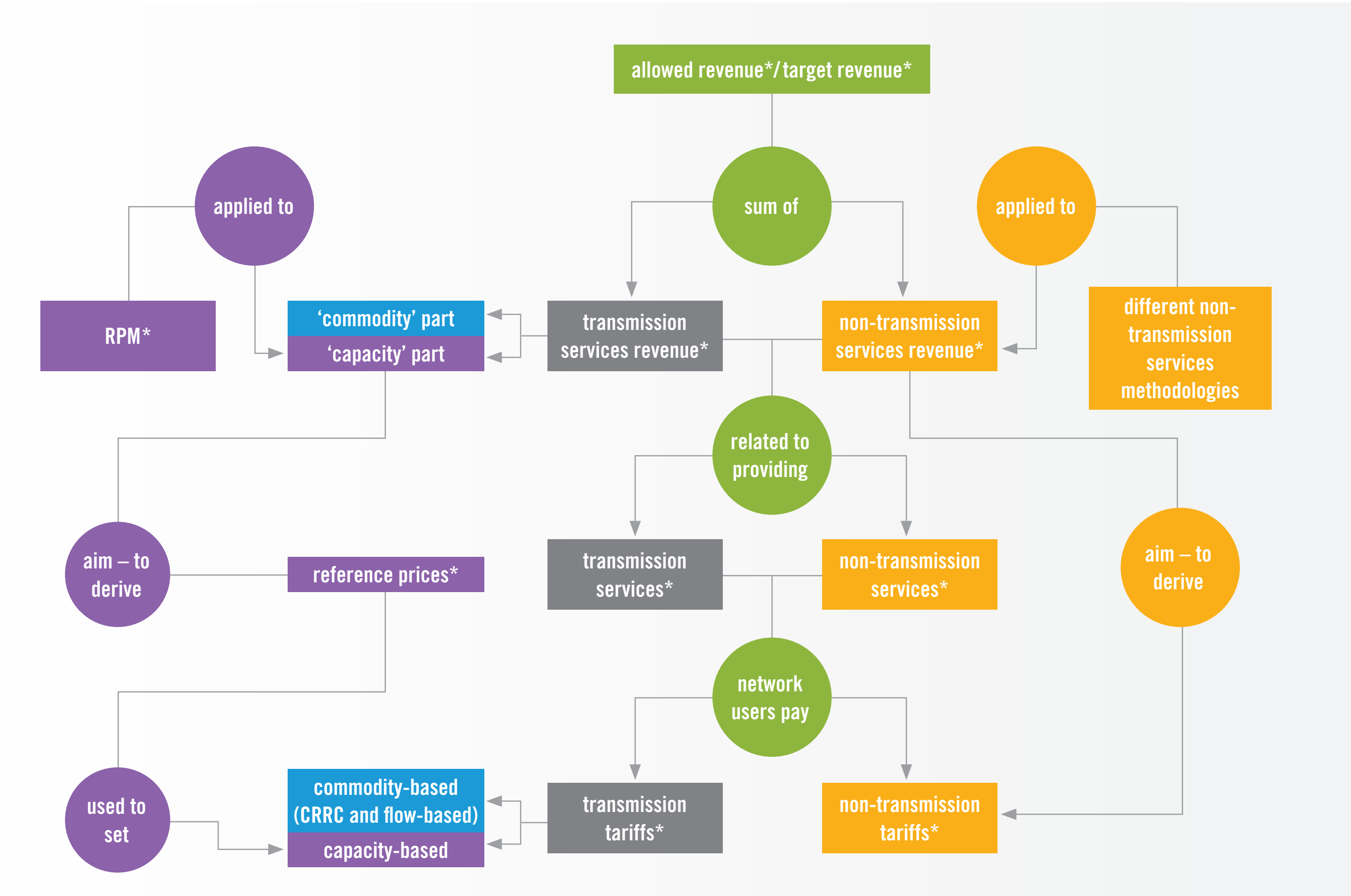


Figure 5: Definitions: revenue and tariffs

1) See 'Glossary of definitions': http://www.entsog.eu/publications/glossary-of-definitions#GLOSSARY-OF-DEFINITIONS

The transmission services revenue splits into a 'capacity' part indicated in purple, and a 'commodity' part in blue. The RPM only applies to the 'capacity' part of the transmission services revenue, to derive a reference price for each entry point and for each exit point. These reference prices, which are explained further below, then provide the basis for capacity-based transmission tariffs. The TAR NC does not require any specific methodology that applies to the 'commodity' part of the transmission services revenue; the sole requirement is for periodic consultation. Without specifying a methodology, Article 4(3) sets out specific requirements for commodity tariffs, as also explained further below.

Turning to the non-transmission services revenue in yellow, different methodologies may apply depending on the particular non-transmission service. Again, the TAR NC does not require any specific methodology; the sole requirement is for periodic consultation[1)]. Without specifying a methodology, Article 4(4) sets out specific requirements for non-transmission tariffs, as explained further below.

For the transmission services revenue, Figure 6 explains the cycle of: (1) applying the RPM to a TSO's transmission services revenue; (2) deriving reference prices for all points on the transmission network; (3) setting capacity-based transmission tariffs; (4) charging such capacity-based transmission tariffs and commodity-based transmission tariffs for the transmission services; and (5) providing such services to recover the transmission services revenue. A similar cycle also applies to non-transmission services revenue.

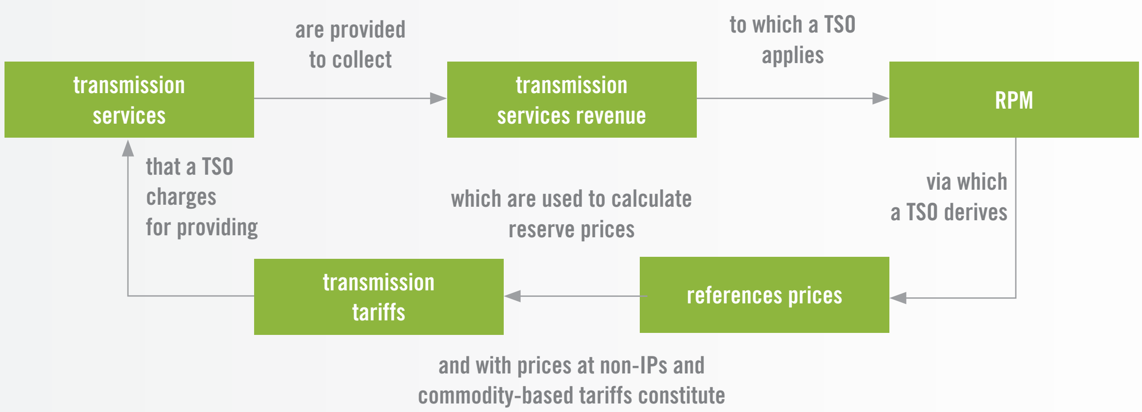


Figure 6: Definitions: cycle of transmission services revenue, tariffs and services

Reference prices and capacity-based transmission tariffs

Applying the RPM results in reference prices for each entry and each exit point of the system. As defined in the TAR NC, a reference price is effectively a price for a firm capacity product with one year duration. It is intentionally not tied to the 'yearly standard capacity product' in the CAM NC, so it applies not only to IPs but also to non-IPs where the CAM NC does not apply.

Figure 7 explains how a given capacity-based transmission tariff derives from a reference price. The 'reference price' does not constitute a capacity-based transmission tariff but is only a 'reference' for setting such tariffs. Figure 7 distinguishes between the points where the CAM NC and the associated auctions apply, and the points where they do not. The first category includes not only IPs but also non-IPs where the NRA has decided to apply the CAM NC. All other points on the transmission network fall into the second category.

1) See Chapter VII 'Consultations Requirements', Section 'Article 26(1) – content of the document for periodic consultation and comparison to Chapter VIII 'Publication Requirements'.

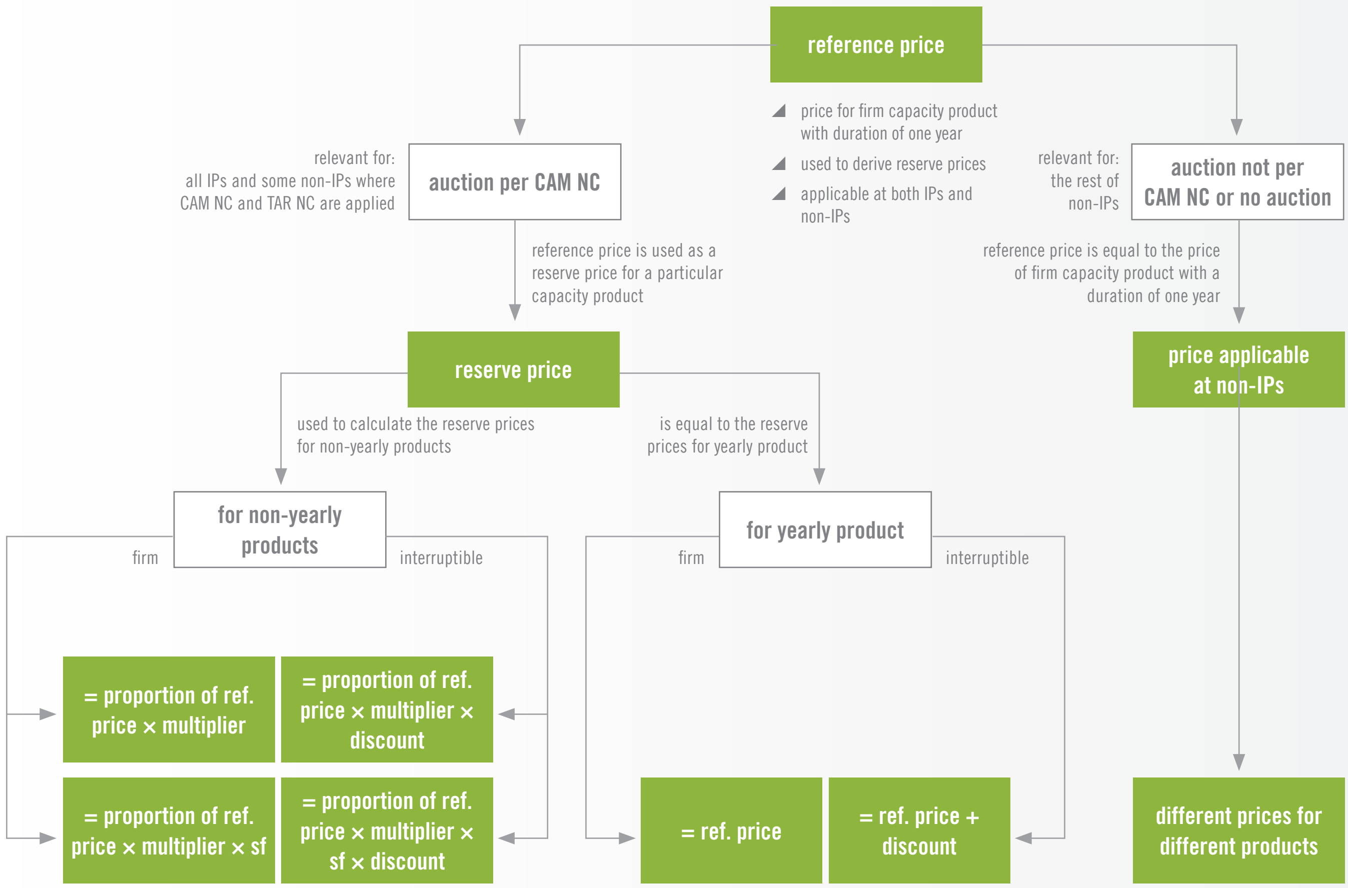


Figure 7: Definitions: reference prices and capacity-based transmission tariffs

As for the first category, reserve prices are set on the basis of reference prices. The CAM NC defines 'reserve price' as the eligible floor price in an auction. Reserve prices are set on the basis of reference prices. Such reserve prices are the capacity-based transmission tariffs for standard capacity products established by Article 9 of the CAM NC: yearly, quarterly, monthly, daily and within-day. The CAM NC establishes specific start and end dates for the duration of such products. The TAR NC sets out the way to set the reserve prices for such products:

- **Yearly standard capacity products:** the reserve prices for firm products are equal to the reference prices; the reserve prices for interruptible products involve the application of a discount to the reserve prices for firm products.
- **The other four standard capacity products:** the reserve prices for firm products are equal to a given proportion of the reference price for a firm yearly product, on top of which a multiplier applies, and potentially a seasonal factor; the reserve prices for interruptible products involve the application of a discount to the reserve prices for firm products.

As for the second category, the TAR NC is silent on the use of the derived reference prices to calculate prices for capacity products. However, the tariff principles in the Gas Regulation still apply.

ARTICLE 3(3) AND 3(17)

NON-PRICE CAP AND PRICE CAP REGIMES

Responsibility: subject to national decision

Without going into the details on setting the regulatory regime, the TAR NC splits all the regulatory regimes into two categories: price cap and non-price cap. The main difference between the two is reflected in what is set: (1) the maximum transmission tariff based on revenue for a price cap regime; or (2) the revenue for a non-price cap regime. Therefore, the concept of 'target revenue' is related to the price cap regime, while the concept of 'allowed revenue' is pertinent to the non-price cap regime. Figure 8 explains this difference.

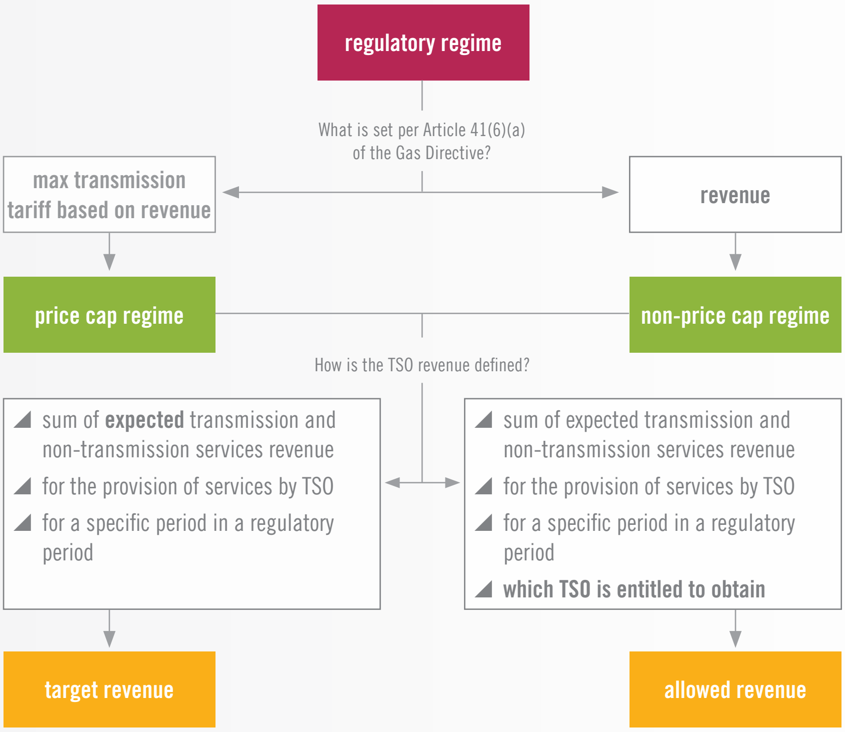


Figure 8: TAR NC regulatory regimes

The TAR NC provides a non-exhaustive list of examples of non-price cap regimes in its definition: revenue cap, rate of return and cost plus. Also, the TAR NC allows for a given TSO to function under both price cap and non-price cap regimes. As of March 2017, the majority of the EU TSOs function under the non-price cap regime. For example, a combination of price cap and non-price cap regimes applies in the Czech Republic and Italy, and the price cap regime applies in Slovakia.

REGULATORY PERIOD AND TARIFF PERIOD

ARTICLE 3(5) AND 3(23)

Responsibility: subject to national decision based on Article 41(6)(a) of the Gas Directive

The TAR NC distinguishes between the concepts of 'regulatory period' and 'tariff period'. The regulatory period is a more general concept, for which *'the general rules for the allowed or target revenue are set'*, while the tariff period stands for the time period *'during which a particular level of reference price is applicable'*.

The TAR NC also sets out the rules regarding the interrelation between the two concepts in terms of their duration. The tariff period is normally shorter than the regulatory period, and one regulatory period comprises several tariff periods. The tariff period may also coincide with the regulatory period, but one tariff period will never be associated with more than one regulatory period. In Austria and Belgium both the regulatory period and tariff period last four years, while in Poland and Sweden they last only one year.

Figures 9 and 10 show different regulatory periods and tariff periods in the MSs whose TSOs are ENTSOG Members[1)]. No information appears for the MSs whose TSOs are ENTSOG's Associated Partners. As part of the implementation of the TAR NC, the NRA may consider to change the tariff period and the regulatory period. The Maps below reflect the situation as of March 2017.

Different regulatory periods

Figure 9 shows the following split of ENTSOG's Members in terms of different regulatory periods: (1) one year for Poland and Sweden; (2) three years for Bulgaria, Portugal and Slovenia; (3) four years for Austria, Belgium, Finland, France, Greece, Hungary, Italy and Luxembourg; (4) five years for Croatia, the Czech Republic, Germany, Ireland, Lithuania, the Netherlands, Northern Ireland, Romania and Slovakia; (5) six years for Denmark; and (6) eight years for Great Britain. In addition:

- The three-year regulatory period indicated for Bulgaria is still subject to NRA approval, and in principle can be from three to five years.
- In Greece the four-year regulatory period has an exception: the latest tariff regulation approved in October 2016 establishes a two-year regulatory period for 2017–2018. Both before and after 2017–2018, the 'normal' regulatory period is four years.
- The Czech Republic has a five-year regulatory period except for the current shorter three-year regulatory period extending from 2016 to 2018. As of 2019, the regulatory period will last at least five years.
- In Spain, parliament established a regulatory period of six years.
- In Great Britain the regulatory period of eight years applies only to National Grid. Interconnector UK does not function under the concept of a regulatory period.

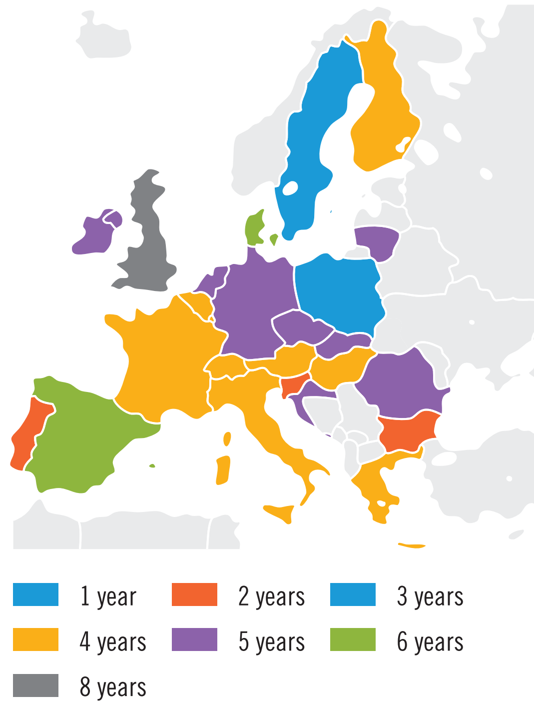


Figure 9: Different regulatory periods in ENTSOG's Members

1) See ENTSOG's website for the list of Members, Associated Partners and Observers: www.entsog.eu/members

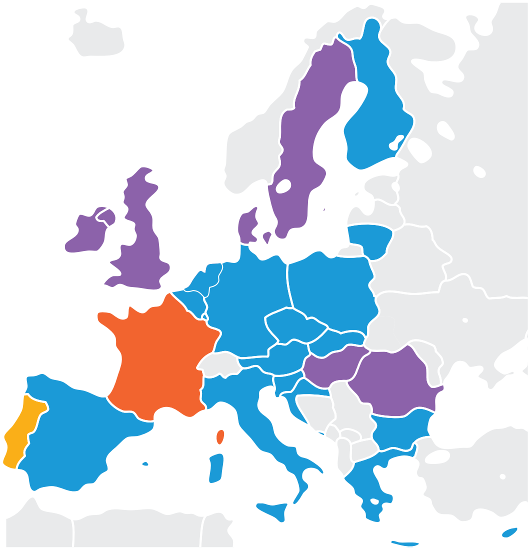


Figure 10: Different tariff periods for ENTSOG's Members

Different tariff periods

Figure 10 shows the following split of ENTSOG's Members in terms of different tariff periods: (1) January–December for Austria, Belgium, Bulgaria, Croatia, Czech Republic, Finland, Germany, Greece, Italy, Lithuania, Luxembourg, the Netherlands, Poland, Slovakia, Slovenia and Spain; (2) April-March for France; (c) July–June for Portugal; and (d) October–September for Denmark, Great Britain, Hungary, Ireland, Northern Ireland, Romania and Sweden.

- In Austria and Belgium the tariff period lasts not one year but four years, although Figure 10 shows that they fall within the category January–December. In Austria the current tariff period is from 1 January 2017 to 31 December 2020, while in Belgium it is from 1 January 2016 to 31 December 2019.
- In Hungary the tariff period appears in Figure 10 as October–September, which will be the case as from October 2017; the current tariff period is January-December.
- In Spain the government sets the tariff period instead of the NRA.

ARTICLE 3(10) HOMOGENEOUS GROUP OF POINTS

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

A homogeneous group of points is a group of points sharing common characteristics. The TAR NC specifies an exhaustive list of homogeneous groups of points. A homogeneous group of points may be composed of points of only one of the following categories: entry IPs, exit IPs, domestic entry points, domestic exit points, entry points from storage facilities, exit points to storage facilities, entry points from LNG terminals, exit points to LNG terminals, and entry points from production facilities.

The concept of homogeneous groups of points appears in the definitions of 'cluster' in Article 3(19) and 'equalisation' in Article 6(4)(b).

Homogeneity does not necessarily imply identical network use at all points within a homogeneous group. Article 5 on CAA distinguishes between intra-system and cross-system network uses. For example, an entry point from storage 'A' may flow gas that will serve mostly 'cross-system use', while an entry point from storage 'B' may flow gas mostly for 'intra-system use'. Despite such a difference in use, all entry points from storage facilities may be considered as a homogeneous group.

CLUSTER OF ENTRY OR EXIT POINTS

ARTICLE 3(19)

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

Clustering is the treatment of a group of entry points or exit points as one entry point or one exit point prior to applying the RPM. Such points can belong to a homogeneous group or be located near each other. The concept of 'homogeneity' does not itself depend on 'vicinity'. With clustering, the selected homogeneous points or points in the vicinity of each other become a single 'virtual' point. The rules for 'how to cluster' are:

- Clustering may apply to some points or all points of the same homogeneous group of points.
- Clustering may apply to some points within the vicinity of each other.
- It is not possible to cluster entry points with exit points.

The capacity of a cluster is the sum of the capacities of the points it brings together. The RPM considers only a cluster in the aggregate, as opposed to its individual points, so the RPM produces a reference price for the cluster as a 'commercial' point although the 'physical' points still exist. Where the RPM requires geographical coordinates for a cluster, it is possible to use a capacity-weighted average of the coordinates of its constituent points, or another approach.

No specific provision in the TAR NC restricts the use of clustering. The clustering decision belongs to the entity in charge of applying the RPM, as decided by the NRA. However, the TAR NC allows clustering for CAA and the capacity weighted distance **('CWD')** counterfactual.

In practice, the main motivation for clustering is a need to reduce the number of points for the application of the RPM. In the absence of clustering, it may be cumbersome and impractical for the RPM to determine reference prices for hundreds of entry and exit points. Clustering offers the advantage of simplified considerations. For example, clustering may apply at either side of an IP where there is more than one TSO, which in practice means more than one entry and/or exit point. If an IP connects TSO A exit with TSO B1 entry and TSO B2 entry, TSO A has two exit points. In such case, both exit points can be considered as one.

Table 1 compares clustering and equalisation, and Annex A provides further details.

COMPARISON BETWEEN CLUSTERING AND EQUALISATION		
Criteria	**Clustering**	**Equalisation**
Definition	Option 1: ◢ Linked to the concept of 'homogeneity'; applicable for some or all points within a homogenous group of points Option 2: ◢ Linked to the concept of 'vicinity'; such points must be within the vicinity of each other	◢ Linked to the concept of 'homogeneity'; applicable for some or all points within a homogenous group of points ◢ No requirement for vicinity
Application	Only ex-ante – before RPM application	Only ex-post – after RPM application
Result	Common reference price for a cluster; no separate reference prices at each physical point within a cluster	Separate and same reference prices at each physical point within a given homogenous group

Table 1: Comparison between clustering and equalisation

Services and Tariffs

ARTICLE 4 OVERVIEW OF ALLOWED TARIFFS

As Figure 5 shows, the TAR NC splits all the regulated services provided by TSOs into two categories: transmission services and non-transmission services. For transmission services, network users pay capacity-based transmission tariffs, and commodity-based transmission tariffs if applicable. For non-transmission services, network users pay non-transmission tariffs.

- Capacity-based transmission tariffs are set on the basis of reference prices derived in accordance with the RPM. Chapter III 'Reserve prices' explains in detail how to set such transmission tariffs for points where the CAM NC applies.
- The TAR NC also allows for setting specific transmission tariffs that consider *'conditions for firm capacity products'*. Such transmission tariffs are only capacity-based, and cannot be commodity-based.
- The TAR NC only allows two types of commodity-based transmission tariffs, as explained further below.
- The setting of non-transmission tariffs depends on the relevant non-transmission service.

TRANSMISSION AND NON-TRANSMISSION SERVICES AND TARIFFS

ARTICLE 4(1) AND 4(4)

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

How to attribute a given service to transmission or non-transmission

Article 3(12) of the TAR NC defines transmission services as *'the regulated services that are provided by the transmission system operator within the entry-exit system for the purpose of transmission'*; Article 3(15) defines non-transmission services as *'the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the transmission system operator'*.

Article 4(1) sets out the criteria for distinguishing between transmission and non-transmission services. The defining characteristics of a transmission service are:

(a) The costs of such service are caused by the cost drivers of both capacity and distance. It is possible to determine capacity by reference to either technical or forecasted contracted capacity.

(b) The costs of such service are related to the investment in and operation of infrastructure that is part of the regulated asset base for the provision of transmission services.

Meeting both criteria requires the classification as a transmission service, otherwise there is an option to classify the service as either a transmission service or a non-transmission service.

Table 2 outlines the attribution algorithm between transmission and non-transmission services.

CRITERIA TO DISTINGUISH BETWEEN TRANSMISSION AND NON-TRANSMISSION SERVICES	
Criteria	**Consequence**
If both conditions (a) and (b) are met	Per first subparagraph of Article 4(1), it IS a transmission service
If condition (a) is not met If condition (b) is not met	Per second subparagraph of Article 4(1), it MAY be a transmission service OR a non-transmission service subject to NRA decision per Article 27(4) on periodic consultation per Article 26

Table 2: Criteria to distinguish between transmission and non-transmission services

Currently, there are many services offered by TSOs which must be assessed in future against the TAR NC criteria above. Examples of such services are:

- Blending and/or ballasting (e.g. Belgium, Italy);
- Odourisation (e.g. Belgium, Denmark, France, Greece, Hungary, Ireland, Italy, Lithuania, Romania);
- Biogas services (e.g. France, Germany, Ireland, Italy, Lithuania);
- Services provided on regional networks (e.g. France, Italy);
- Dedicated compression services (e.g. France, Great Britain, Ireland, Lithuania, Poland);
- Dedicated metering services (e.g. Belgium, Lithuania, Germany, Ireland, Italy, France, Great Britain);
- Dedicated pressure services (e.g. Belgium, France, Germany, Ireland, Italy, Lithuania);
- Dedicated connections (e.g. Austria, Belgium, Germany, Great Britain, Greece, Hungary, Ireland, Italy, Lithuania).

Requirements for non-transmission services

Article 4(4) of the TAR NC includes a set of requirements for the tariffs applicable to non-transmission services: cost-reflectivity, non-discrimination, objectivity, transparency and minimising cross-subsidisation.

To minimise cross-subsidisation one criterion is to target the application of non-transmission tariffs to the beneficiaries of the relevant non-transmission services. However, Article 4(4) also envisages that a given non-transmission service may benefit not only a particular beneficiary but all network users. If it is not possible to identify a beneficiary, then the costs should be allocated to all network users.

The requirements of Article 4(4) apply to all non-transmission services and tariffs. However, the process for NRA approval differs for non-transmission services provided to network users, and for non-transmission services provided to parties other than network users[1].

- Non-transmission services provided to network users are subject to the requirements of periodic consultation, NRA approval and review per Articles 26 and 27, and subject to publication per Article 30. The relevant requirements address: (1) the stakeholder concerns of additional transparency for charges that network users must pay; and (2) the need to preserve the confidentiality of potentially commercially sensitive information.
- TSOs may provide non-transmission services to parties other than network users, such as infrastructure operators and telecom service providers. If the recipient is not a network user, then the non-transmission service does not fall under the requirements mentioned above for non-transmission services provided to network users. In any case, Article 4(1) subjects the split between transmission and non-transmission services to periodic consultation, NRA approval and review per Articles 26 and 27.

1) Article 2(1)(11) of the Gas Regulation defines 'network user' as *'a customer or a potential customer of a transmission system operator, and transmission system operators themselves in so far as it is necessary for them to carry out their functions in relation to transmission'*.

TRANSMISSION TARIFFS FOR FIRM CAPACITY PRODUCTS WITH ‘CONDITIONS’

ARTICLE 4(2)

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

Article 4(2) of the TAR NC mentions *‘conditions for firm capacity products’*. Some systems have introduced such firm capacity products with ‘conditions’ for the efficient use of the network, and to maximise the offer of firm capacity taking into account market and network characteristics. Examples include Austria, Belgium, Germany, Luxembourg and the Netherlands. The TAR NC permits the determination of transmission tariffs in a certain ‘manner’ that considers these conditions.

Entry-exit systems aim for independent and seamless use of flexible entry and exit capacity regardless of underlying system characteristics, and at times across different networks operated by different TSOs. In reality physical flows, the design of the networks and their interaction constrain the ability of TSOs to guarantee firm and freely allocable capacity, and it is not always efficient to try and surmount physical constraints with additional investment. In the presence of constraints, introducing ‘conditions’ to firm standard capacity products aims for the efficient use of the network.

Article 38(4) of the Amended CAM NC calls for ACER to produce a report on *‘conditionalities’* set out in firm capacity products contracts *‘having regard to their effect on efficient network use and the integration of the Union gas markets’*. ACER should prepare its report with the support of relevant NRAs and TSOs, *‘in the framework’* of its monitoring task, and within two years of the Amended CAM NC’s entry into force, which coincides with the entry into force of the TAR NC.

Annex B outlines some examples of currently offered firm capacity products with ‘conditions’.

In accordance with the EU and national rules, other products may be introduced for greater efficiency of the use of the transmission system.

ARTICLE 4(3) CAPACITY- AND COMMODITY-BASED TRANSMISSION TARIFFS

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

General

Article 4(3) of the TAR NC establishes the rule that by default, transmission tariffs must be capacity-based. The only allowed exceptions are two commodity-based transmission tariffs: (1) a 'flow-based charge' which may be established to cover costs that are mainly driven by the volume actually flowed; and (2) a 'complementary revenue recovery charge' **('CRRC')** to manage revenue under- and over-recovery. See below for details.

The composition of a TSO's transmission services revenue may include capacity-based transmission tariffs derived from the RPM, and commodity-based transmission tariffs. Note that the capacity-commodity split of the transmission services revenue can be done before applying the RPM *(ex-ante)*, or after *(ex-post)* as with CRRC.

Flow-based charge

TSOs incur certain costs that vary with the quantity of gas flowed. A key example is shrinkage gas, the main component of which is compressor fuel. As gas demand increases, the TSO has to switch on more compressors to maintain system pressures, and therefore requires more gas or electricity for compressor fuel. A flow-based charge provides one way of recovering the associated costs from network users. According to Article 4(3)(a)(ii), the charge must be the same at all entry points and the same at all exit points, thus allowing a distinction between all entry points and all exit points but not between separate entry points or separate exit points.

The TAR NC clarifies the ability to express the flow-based charge either in monetary terms, or 'in kind' in terms of gas volumes or energy amounts. When charged in kind, network users must supply the TSO a flow-related quantity of gas to cover some cost elements directly related to volumes injected or withdrawn from the network, such as the costs of operating compression stations, losses, shrinkage and unaccounted for gas. The NRA sets or approves the charge in advance, which applies as a percentage to volumes injected/withdrawn by users at entry/exit points. Depending on the particular system, such a charge can provide advantages for TSOs, network users and the system in general, mainly in terms of simplicity and cost-reflectivity.

Complementary revenue recovery charge

The TAR NC also allows an additional commodity-based transmission tariff at points other than IPs. This CRRC serves the purpose of managing revenue under- and over-recovery. The CRRC can work in conjunction with adjustments to the application of RPM such as rescaling. The use of rescaling may be appropriate to set a capacity-based transmission tariff that generates the capacity part of transmission services revenue, while a commodity-based CRRC can manage any under-recovery. Where used, the CRRC applies to the flows of all network users irrespective of their portfolio of capacity products at points other than IPs.

NRAs must assess the cost-reflectivity of the CRRC, and the impact of any cross-subsidisation between IPs and non-IPs. The CAA concern the total transmission service revenue and not just the portion generated by capacity bookings. As outlined below, CAA relate to the transmission services revenue from the capacity-based transmission tariffs, and separately to the transmission services revenue from the commodity-based transmission tariffs. The CRRC affects the collective results of CAA.

Difference between a flow-based charge and a complementary revenue recovery charge

Table 3 outlines the difference between the two charges.

COMPARISON BETWEEN A FLOW-BASED CHARGE AND CRRC

Charge	Aim	Which points	How expressed	Calculation	Approval requirements
Flow-based charge	Cover the costs mainly driven by the quantity of the gas flow	All points	In monetary terms or in kind	On the basis of forecasted or historical flows, or both Same at all entry points and same at all exit points	Consultation per Article 26(1)
CRRC	Managing revenue under-/over-recovery	Non-IPs	In monetary terms	On the basis of forecasted or historical capacity allocations, or both	Consultation per Article 26(1) NRA assessment of its cost-reflectivity and its impact on cross-subsidisation between IPs and non-IPs

Table 3: Comparison between a flow-based charge and CRRC

Cost Allocation Assessments

ARTICLE 5 COST ALLOCATION ASSESSMENTS

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA, a possible deviation needs to be justified by the NRA in the decision

As part of the periodic consultation [1)], NRAs will decide whether TSOs or NRAs perform up to two assessments to comply with the principle of avoiding cross-subsidies between network uses. One assessment is for **capacity charges**, the other, if any, is for **commodity charges**. These assessments help indicate the cost-reflectivity of proposed tariffs based on the cost drivers set out in Article 5(1). The assessments involve calculations that may be based on forecasted revenues, bookings, flows and cost drivers, potentially based on historical data.

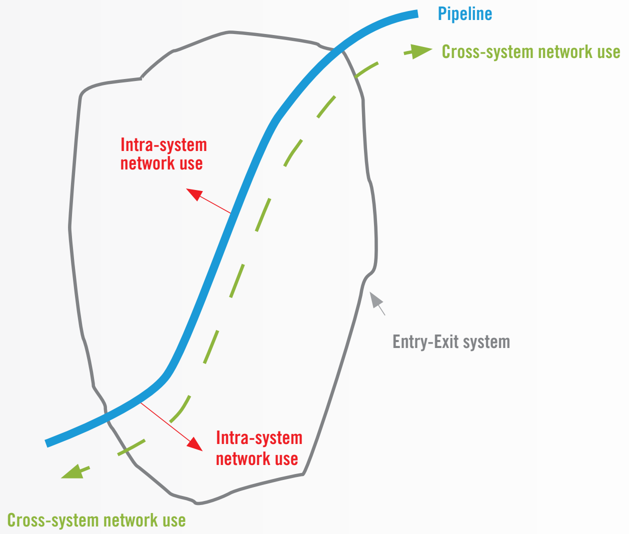


Figure 11: Basis for performing cost allocation assessments

1) See Chapter VII 'Consultations requirements', Section 'Article 26(1) – content of the document for periodic consultation and comparison to Chapter VIII 'Publication requirements'.

Capacity assessment:

compares the transmission system revenue to be collected from capacity charges for intra-system and cross-system network uses ($\mathrm{Revenue}_{\mathrm{cap}}^{\mathrm{intra}}$ and $\mathrm{Revenue}_{\mathrm{cap}}^{\mathrm{cross}}$), taking into account cost drivers ($\mathrm{Driver}_{\mathrm{cap}}^{\mathrm{intra}}$ and $\mathrm{Driver}_{\mathrm{cap}}^{\mathrm{cross}}$). The capacity assessment compares the intra-system capacity ratio ($\mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{intra}}$) to the cross-system capacity ratio ($\mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{cross}}$).

$$\mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{intra}} = \frac{\mathrm{Revenue}_{\mathrm{cap}}^{\mathrm{intra}}}{\mathrm{Driver}_{\mathrm{cap}}^{\mathrm{intra}}}$$

$$\mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{cross}} = \frac{\mathrm{Revenue}_{\mathrm{cap}}^{\mathrm{cross}}}{\mathrm{Driver}_{\mathrm{cap}}^{\mathrm{cross}}}$$

The ratio comparison involves a 'capacity cost allocation comparison index' ($\mathrm{Comp}_{\mathrm{cap}}$) calculated as follows:

$$\mathrm{Comp}_{\mathrm{cap}} = \frac{2\times|\mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{intra}} - \mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{cross}}|}{\mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{intra}} + \mathrm{Ratio}_{\mathrm{cap}}^{\mathrm{cross}}}\times 100\%$$

Commodity assessment:

the commodity assessment compares transmission services revenue collected from commodity charges for intra-system and cross-system network use ($\mathrm{Revenue}_{\mathrm{comm}}^{\mathrm{intra}}$ and $\mathrm{Revenue}_{\mathrm{comm}}^{\mathrm{cross}}$), taking into account cost drivers ($\mathrm{Driver}_{\mathrm{comm}}^{\mathrm{intra}}$ and $\mathrm{Driver}_{\mathrm{comm}}^{\mathrm{cross}}$). The commodity assessment compares the intra-system commodity ratio ($\mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{intra}}$) to the cross-system commodity ratio ($\mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{cross}}$).

$$\mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{intra}} = \frac{\mathrm{Revenue}_{\mathrm{comm}}^{\mathrm{intra}}}{\mathrm{Driver}_{\mathrm{comm}}^{\mathrm{intra}}}$$

$$\mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{cross}} = \frac{\mathrm{Revenue}_{\mathrm{comm}}^{\mathrm{cross}}}{\mathrm{Driver}_{\mathrm{comm}}^{\mathrm{cross}}}$$

The ratio comparison involves the 'commodity cost allocation comparison index' ($\mathrm{Comp}_{\mathrm{comm}}$) calculated as follows:

$$\mathrm{Comp}_{\mathrm{comm}} = \frac{2\times|\mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{intra}} - \mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{cross}}|}{\mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{intra}} + \mathrm{Ratio}_{\mathrm{comm}}^{\mathrm{cross}}}\times 100\%$$

For both assessments, the intent is to guarantee against undue cross-subsidies on capacity or commodity by checking that the revenue-to-cost ratio for intra-system use is broadly similar to the revenue-to-cost ratio for cross-system use. Any ratio above 10 % requires a justification by the NRA in its decision under Article 27(4) following consultation under Article 26.

Annex C provides an example showing how to perform the CAA.

Chapter II: Reference Price Methodologies

Chapter II 'Reference Price Methodologies' has the following structure: after an introduction, Articles 6 to 8 address 'general requirements' for RPM; Article 9 elaborates on 'adjustments at certain points', meaning points to/from storage facilities, from LNG facilities and to/from infrastructure ending the isolation of MSs; Articles 10 and 11 set out the arrangements in 'multi-TSO entry-exit systems'.

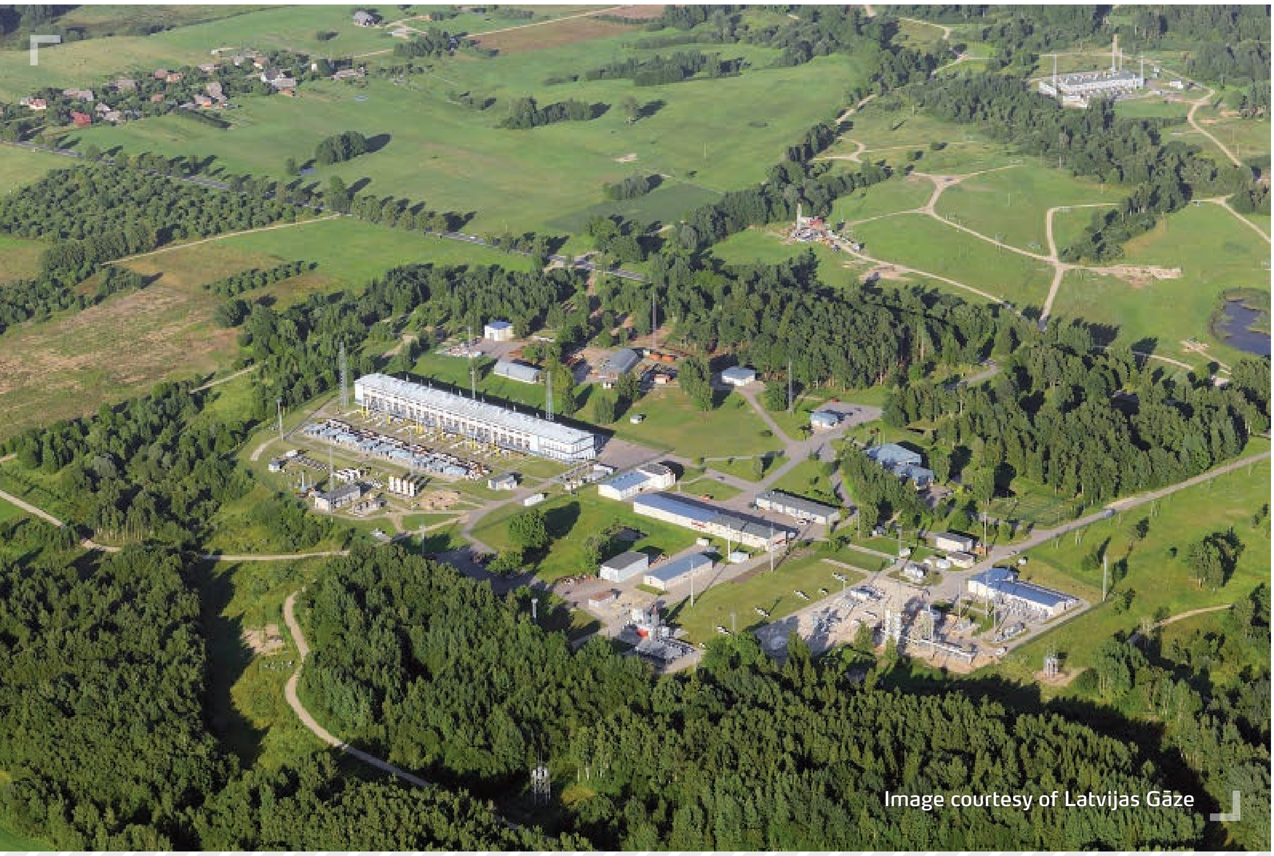


Image courtesy of Latvijas Gāze

Summary

Scope: IPs and non-IPs
Application date: 31 May 2019

This Chapter addresses the **methodologies** that determine **reference prices**. A reference price applies to a yearly firm standard capacity product for each entry and exit point, and provides the basis for calculating the reserve prices for the different standard firm and interruptible capacity products.

A general requirement is to apply the same RPM at all the entry and exit points within an entry-exit system: both IPs and non-IPs. The only exception is for a **multi-TSO entry-exit system**. If such a system is located within a MS, the same RPM should apply jointly to all TSOs involved by default. As an exception and subject to specific requirements, it is also possible to apply the same RPM separately to each TSO involved. Another exception permits the application of different RPMs when planning entry-exit system mergers.

The TAR NC does not prescribe default rules or specific requirements for multi-TSO entry-exit systems spanning more than one MS. Therefore, the TSOs involved can apply the same RPM jointly or separately, or different RPMs.

The TAR NC does not insist on a particular RPM. Instead, it specifies the **requirements** for such methodologies: their aims and the possible adjustments within the RPM. Chapter VII 'Consultation requirements' calls for a consultation document explaining how the proposed RPM meets such requirements. The TAR NC requires a comparison of the resulting indicative reference prices to those derived from the clearly defined CWD counterfactual.

This Chapter also permits discounts for entry-points-from/exit-points to **storage facilities**. The discounts apply to reference prices, and by default must be no less than 50 %, but can be less than 50 % in specific cases. Discounts are subject to a TSO/NRA consultation conducted at least every five years. Discounts are also possible at entry-points-from **LNG facilities**, and at entry-points-from/exit-points-to **infrastructure ending the isolation** of gas transmission systems in certain MSs. These discounts are subject to NRA consultation every tariff period.

LINK BETWEEN REVENUE, ALLOCATION OF COSTS, REVENUE RECOVERY

Responsibility: RPM determination is subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

The choice of RPM is a key decision for a TSO or NRA, and is a central topic of the TAR NC. The RPM determines how to allocate the TSO's costs among entry and exit points, how the TSO recovers its revenue, and how to charge network users.

The TAR NC contemplates an initial NRA decision on a RPM, and a required consultation at least every five years thereafter. As explained above, the collection of transmission services revenue must be based primarily on capacity charges in accordance with Article 4(3).

Figure 12 shows how the RPM fits within a series of several required analytical steps, which together lead to the determination of a TSO's revenue recovery.

- The TAR NC does not restrict the choice of RPM, since a TSO/NRA can consider any methodology as long as the assessment involves a comparison to the CWD counterfactual in the final consultation document. The TAR NC does not in fact detail any possible RPM except for the CWD counterfactual.
- Only the requirements of Article 7 limit the free selection of parameters and assumptions for the RPM.

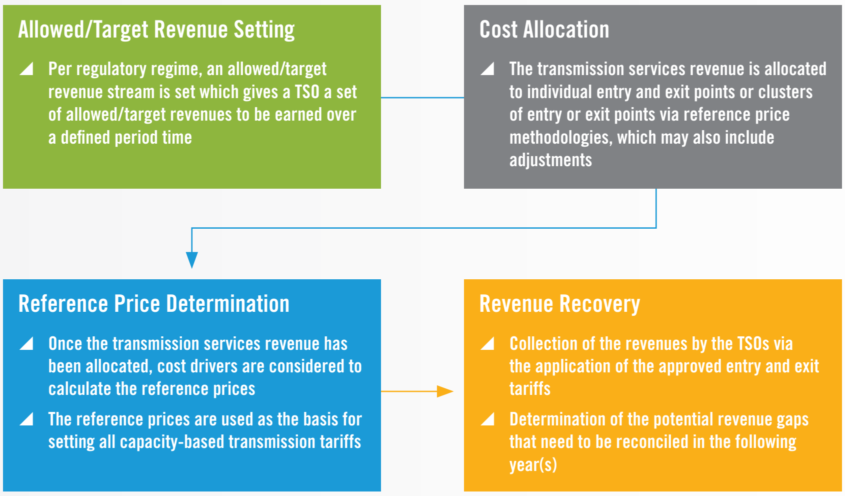


Figure 12: Link between revenue reconciliation, cost allocation, reference price determination and revenue recovery

General Requirements

REFERENCE PRICE METHODOLOGY APPLICATION

ARTICLE 6

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

Figure 13 shows that the RPM does not apply to all the TSO's allowed/target revenue but only to the portion related to the provision of transmission services, and only to those services involving capacity-based transmission tariffs. Chapter I explained that a 'reference price' derived through the RPM does not constitute a capacity-based transmission tariff but is only a 'reference' for setting such tariffs[1]. The TAR NC does not detail any possible RPM except for the CWD counterfactual.

Apart from discounts at certain points, described further below in this Chapter, Article 6 allows for three kinds of adjustments to the RPM: benchmarking, equalisation and rescaling.

- Benchmarking implies that the NRA adjusts the reference price at an entry or exit point so that the resulting values meet the competitive level of reference prices.
- Under equalisation, the TSO or NRA to apply the RPM sets the same reference price at some or all points of a group sharing the same set of characteristics, such as LNG points.
- Rescaling involves the adjustment of the reference price at some or all entry and/or exit points, through the application of a constant that can be multiplicative or positive/negative additive.

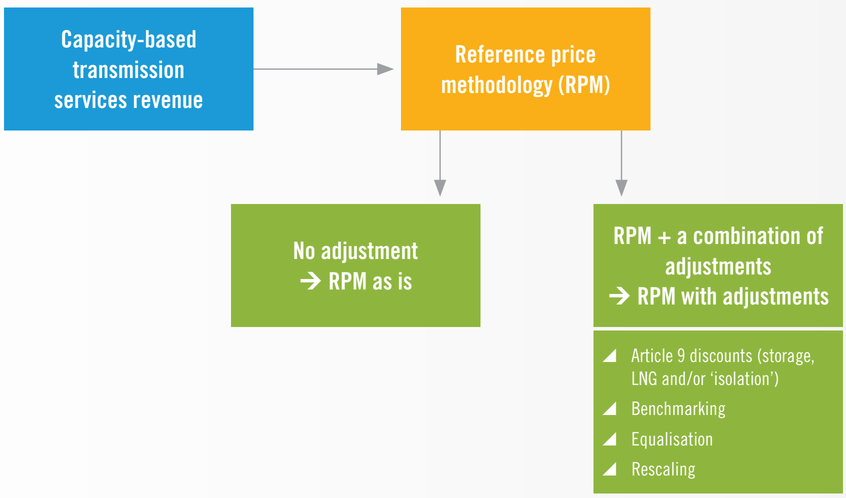


Figure 13: Possible components of a RPM

1) See Chapter 1 'General Provisions', Section 'Article 3 – definitions'.

ARTICLE 6(4) BENCHMARKING, EQUALISATION AND RESCALING

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

General

As explained above, the TAR NC explicitly lists a limited number of 'adjustments' to the application of RPM: benchmarking, equalisation, rescaling and adjustments at entry-points-from/exit-points-to storage facilities, at entry-points-from LNG facilities, or at entry-points-from/exit-points-to infrastructure ending the isolation of MSs. The list included in the TAR NC does not prevent the use of various steps in constructing the proposed RPM. Regardless of the proposed RPM and its steps, the key procedural requirements entail periodic consultation, comparison against CWD, and NRA approval.

Benchmarking

Following the Gas Regulation, the NRA can perform benchmarking in order to adjust the reference price at a given entry or exit point if the point faces competition from the entry or exit point(s) of other TSOs. The adjustment should bring the resulting reference price in line with the competitive level set by competing points.

Equalisation

Equalisation means the application of the same reference price to some or all points within a homogeneous group. Where necessary, equalisation seeks to ensure the same reference prices at points deemed similar because of their characteristics. An initial application of the RPM may imply large differences in reference prices for similar points, so equalisation would constitute a correction at a second or 'ex-post' stage of the process. The rules for 'how to equalise' are:

- Equalisation may apply to some or all points of the same homogeneous group.
- Equalisation is not permitted among points that do not belong to the same homogeneous group.

Table 1 compares clustering and equalisation.

The TAR NC does not explicitly restrict equalisation. When applying equalisation, the entity in charge may compare the potential simplicity offered by equalisation to the efficiency gains that locational signals offer, based on information provided in the public consultation.

Several factors may motivate equalisation in practice, including but not limited to the need to avoid cross-subsidies, especially regarding cross-system and intra-system uses; to encourage the use of assets that offer security of supply; to enhance the stability of prices and flows, especially in cases where reference prices were already equalised before implementing the TAR NC; to foster retail and wholesale market competition; for simplicity and transparency; or the simple desire to avoid price differences within homogeneous groups of points.

For each homogeneous group, the decision on equalisation should assess the pros and cons of equalisation relative to the alternative of locational signals. Locational signals offer the advantage of incorporating cost drivers such as distance and capacity, with the goal of enhancing cost-reflectivity.

Equalisation is used as an ex-post mechanism after the RPM application. After all reference prices for all points are calculated, homogeneous points subject to equalisation have their reference prices equalised so that the resulting prices are the same.

Rescaling

The primary use of rescaling is to ensure the recovery of allowed revenue while respecting the entry-exit split.

Rescaling can entail multiplying reference prices by a certain value, or adding/subtracting a certain value. The choice depends on the RPM used.

- Multiplication can calibrate desired locational signals up or down, maintaining their percentage differences, while permitting an adjustment of expected revenue to match the allowed transmission services revenue.
- Addition ensures the recovery of allowed revenue and can avoid zero or negative reference prices.

A simple example illustrates the differences between the two approaches and their relative merits. Assume that tariffs post RPM are € 1, 2 and 3 for IP1, IP2 and IP3 respectively, but that they would only recover € 50 while the TSO's allowed revenue are € 100:

- Multiply all tariffs by 2, to produce tariffs of € 2, 4 and 6. Advantage: the relative percentage differences between the tariffs remain the same. Drawback: cannot address the issue of negative or zero tariffs.
- Add the same amount of € 2 to each IP, producing tariffs of € 3, 4 and 5. Drawback: the new set changes the percentage difference in tariffs. IP3's tariff exceed IP2's by 50 % prior to addition, as € 3 is 50 % more than € 2. After addition, IP3's tariff costs only 25 % more: € 5 compared to € 4. Advantage: can address the issue of negative or zero tariffs after the application of RPM. If we modify the IP1 tariff in this example to € –1 prior to addition, then the € +2 adjustment would bring it to € +1.

ARTICLE 7 CHOICE OF A REFERENCE PRICE METHODOLOGY

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

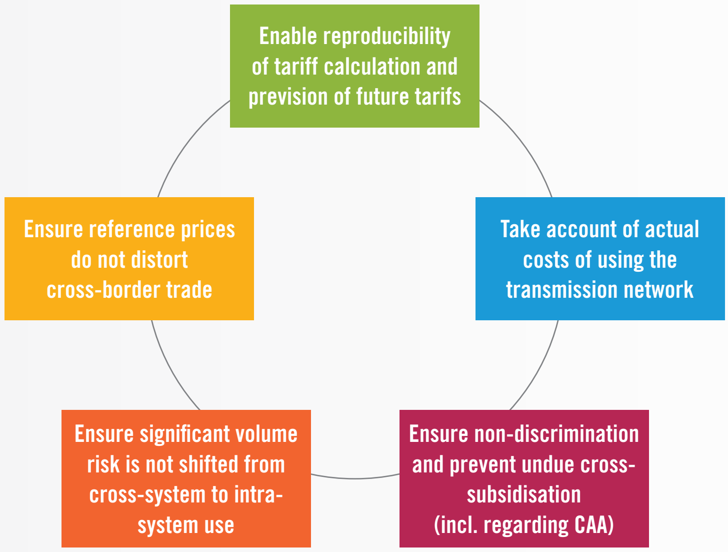


Figure 14: Principles for the choice of a RPM

TSOs/NRAs have to ensure compliance with five principles when evaluating a certain RPM:

- **Reproducibility:** network users should know the methodology to derive tariffs, should be able to reproduce the tariff calculations and should have the ability to forecast tariff developments over time.
- **Cost-reflectivity:** tariffs should reflect the costs incurred by the TSO.
- **Non-discrimination:** means that to the extent possible, TSOs should avoid cross-subsidies where some network users pay for others. The assessments set out for the CAA test the satisfaction of this principle.
- **Volume risk management:** one group such as intra-system network users should not face tariff hikes to compensate for the diminishing use of the network by another group such as cross-system network users.
- **Non-distortion of cross-border trade** through reference prices implies that reference prices derived in accordance with RPM should ensure non-distorted economic signals for cross-border trade.

CAPACITY WEIGHTED DISTANCE REFERENCE PRICE METHODOLOGY

ARTICLE 8

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides – only for comparison purposes with the proposed RPM; subject to decision by NRA

CWD assumes that the share of the allowed revenue to collect from each entry or exit point should be proportionate to its contribution to the cost of the system's capacity and to the distance between it and all exit points or all entry points. The resulting tariff would be uniform per unit of capacity and distance.

CWD is the only counterfactual set out in the TAR NC, which means that all TSOs will have to compare the tariffs under their chosen RPMs to CWD tariffs. Applying CWD without modification would eliminate the need for any counterfactual. However, the comparison against CWD still applies if any modifications to parameters and/or steps as set out in Article 8 are made, leading to a 'Modified CWD'. The counterfactual CWD can calculate the reference prices for each point, for clusters of points, or both.

As of March 2017, some European TSOs apply a Modified CWD, such as in France, Belgium and Germany. Annexes D and E provide a process and an example of CWD methodology under Article 8.

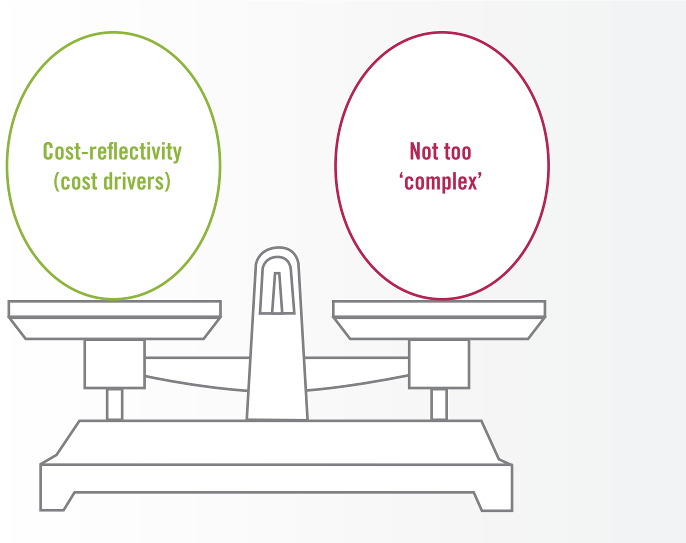


Figure 15: Balance for CWD RPM

DISTANCE CALCULATION

ARTICLE 8(1)

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

Shortest pipeline distance for capacity weighted distance reference price methodology

To measure distance for the CWD, Article 8 considers the pipeline approach, which selects the shortest distance of the pipeline routes between: (1) an entry point or a cluster of entry points; and (2) an exit point or a cluster of exit points.

Clustering introduces two possibilities:

- 'Distance before cluster': calculate the weighted average of the shortest pipeline distances of all physical points of the cluster. The weights can depend on the technical capacity.
- 'Cluster before distance': select a focal point of the cluster, and then calculate the shortest distance of the pipeline routes from or to such a focal point. A dominant physical point of the cluster can constitute the focal point.

When applying CWD, Article 8 does not consider other distance methodologies such as: (1) average pipeline distance, as opposed to the shortest; and (2) airline distance. However, a TSO/NRA can consider such methodologies within a proposed alternative RPM, including a Modified CWD. Below are two examples of alternative approaches to distance.

Approaches other than allowed for capacity weighted distance reference price methodology

Average pipeline distance

In general, pipeline distance is the distance along a defined pipeline. If two or more pipelines with different lengths connect the same entry and exit point, then it is possible to calculate alternative distances; one can determine both the shortest distance and the average.

The calculation of average distance could require a large amount of data, since a TSO's networks often contains many entry and exit points. It can be useful to simplify the representation of the network to simplify the calculation of average distances.

Airline distance

The airline distance is the result of computations that apply the Pythagorean Theorem to coordinates assigned to each point. Airline distance is analogous to using a ruler to measure the distance between two points on a flat map.

The logic of the calculation is: (a) to assign coordinates to each point: easting and northing; and (b) to apply the following formula:

$$\mathrm{Distance}_{\mathrm{En,Ex}} = \sqrt{(\mathrm{East}_{\mathrm{En}} - \mathrm{East}_{\mathrm{Ex}})^2 + (\mathrm{North}_{\mathrm{En}} - \mathrm{North}_{\mathrm{Ex}})^2}$$

Where:

$\mathrm{Distance}_{(\mathrm{En,Ex})}$	distance between the entry point and the exit point in km;
$\mathrm{East}_{\mathrm{En}}$, $\mathrm{East}_{\mathrm{Ex}}$	easting of the entry or exit point according to the projected coordinate system;
$\mathrm{North}_{\mathrm{En}}$, $\mathrm{North}_{\mathrm{Ex}}$	northing of the entry or exit point according to the projected coordinate system.

Assuming a flat surface implies an approximation only, whose accuracy may be sufficient depending on terrain topography. Airline distance does not consider the extra length of detours that uneven terrain may require, and does not consider differences in altitude.

There are two ways to calculate airline distance:

- The Universal Transverse Mercator projected coordinate system (UTM), introduced across Europe;
- Geo Information System (GIS), software normally available to TSOs, which allows for the calculation of distance independent of the coordinate system used.

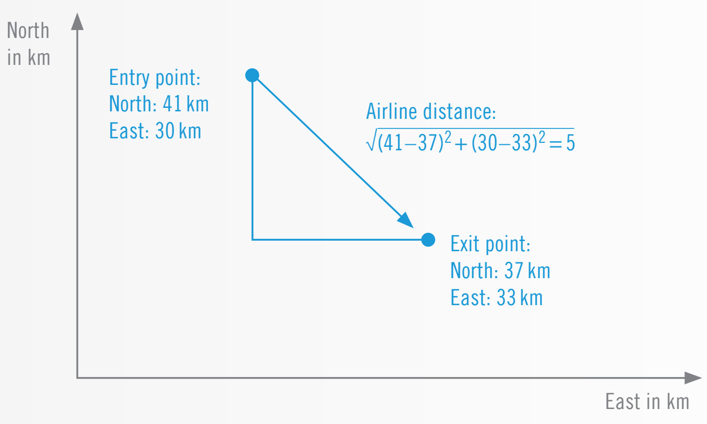


Figure 16: Simple example of airline distance calculation

ENTRY-EXIT SPLIT

ARTICLE 8(1)e

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

One RPM parameter is the split between revenue derived from entry points and exit points. The entry-exit split may be either an input to the RPM or an output.

Article 8(1)(e) requires the counterfactual CWD to use a 50/50 entry-exit split as an input. The TAR NC does not define the entry-exit split for the proposed and approved RPM, but Article 30(1)(b)(v)(2) requires its publication. In any case, the broader principles established by Article 13 of the Gas Regulation always apply.

Table 4 below provides a simple example showing the result of different entry-exit splits using the postage stamp methodology. Where the entry-exit split is an *input*, the split sets the entry and exit revenues, which then determine the tariffs. The steps appear in sequence from left to right. Where the entry-exit split is an *output*, the calculation of the tariffs comes first. The example assumes identical entry and exit tariffs under the postage stamp RPM, and the steps then proceed from right to left, ending in the derivation of the split based on the percentage of revenue recovery yielded by the identical tariffs. The cells show the numbering of the steps.

THE EFFECT OF DIFFERENT ENTRY-EXIT SPLITS TO THE TARIFFS				
Assumptions				
Transmission services revenue	€ 100			
Forecasted contracted entry capacity	25 units			
Forecasted contracted exit capacity	50 units			
Calculation				
1. Entry-exit split as input	2. Total entry revenues	2. Total exit revenues	3. Entry tariff	3. Exit tariff
50 : 50	50 % × € 100 = € 50	50 % × € 100 = € 50	€ 50/25 units = € 2.0/unit	€ 50/50 units = € 1.0/unit
40 : 60	40 % × € 100 = € 40	60 % × € 100 = € 60	€ 40/25 units = € 1.6/unit	€ 60/50 units = € 1.2/unit
3. Entry-exit split as output	2. Total entry revenues	2. Total exit revenues	1. Entry tariff	1. Exit tariff
33 : 67	25 units × € 1.33/ unit = € 33	50 units × € 1.33/ unit = € 67	€ 100/75 units = € 1.33/unit	€ 100/75 units = € 1.33/unit

Table 4: The effect of different entry-exit splits on the tariffs

Adjustments at Certain Points

ARTICLE 9 Discounts at entry-points-from/exit-points-to storage facilities and infrastructure ending the isolation, and at entry-points-from LNG facilities

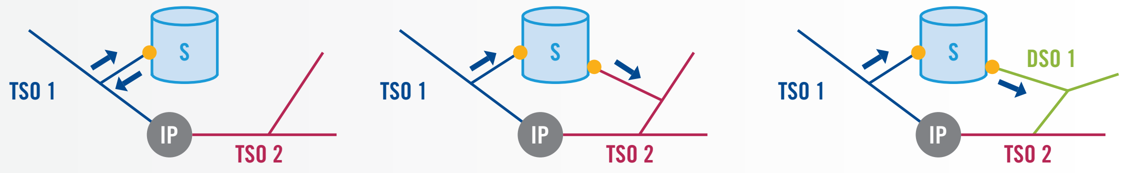
Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

Storage points

Default rule: storage connected to 1 TSO only → entry and exit discounts of **at least 50 %**

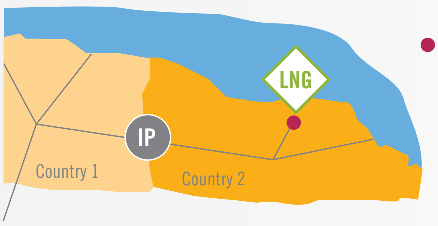
Exception 1: storage connected to 2 TSOs and in competition with an IP

Exception 2: storage connected to 1 TSO and 1 DSO in competition with an IP



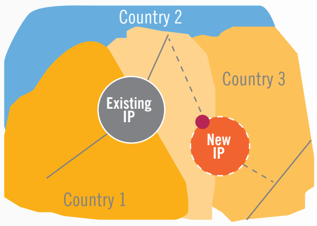
TSO entry and exit points from/to storage

LNG entry points and other points to infrastructure to end isolation of MSs for security of supply purposes



TSO entry point from LNG

Discounts possible at LNG entry point to reduce Country 2 dependence with IP Country 1



TSO entry and exit points from/to infrastructure (here: new IP) to end isolation of Country 2

Discounts possible at the entry point or exit point of the new IP to end isolation of Country 2

Figure 17: Discounts at entry-points-from/exit-points-to storage facilities and infrastructure ending the isolation, and at entry-points-from LNG facilities

TAR NC allows TSOs to set tariff discounts for storage points, LNG regasification points and infrastructure aiming at removing gas supply isolation. The discounts are in effect adjustments to the results of the RPM, but separate from the benchmarking, rescaling and equalisation identified in Article 6.

As a default, storage discounts must be at least 50 %, to avoid double charging and to take account of the contribution that storage facilities make in avoiding the need for additional gas transmission investments. The TAR NC envisages exceptions where a storage facility is also connected to at least one other TSO or DSO system, if network users use the storage facility as an alternative to an IP, as in Germany and Slovakia. Some TSOs in this situation reduce the discount, and Annex F provides an example of such an approach.

Discounts may also apply to LNG entry points to increase security of supply. The TAR NC is silent as to the appropriate level of such discounts.

Discounts may also apply to entry-points-from/exit-points-to infrastructure ending the isolation of MSs, if such discounts increase security of supply. The TAR NC is similarly silent as to the appropriate level of such discounts.

Multi-TSO Entry-Exit Systems

MULTI-TSO ARRANGEMENTS

ARTICLES 10 AND 11

Responsibility: subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

General

Article 10 addresses multi-TSO arrangements in entry-exit systems within one MS. Current examples are Austria, France, Germany, Hungary, Italy and Spain. Article 11 addresses multi-TSO arrangements in an entry-exit system covering more than one MS, like the current system that extends across Belgium and Luxembourg.

Application of same/different reference price methodology jointly/separately by TSOs involved

Subject to exceptions, Article 6(3) of the TAR NC requires the application of the same RPM to all entry and exit points in a given entry-exit system. This general rule applies within a MS regardless of the presence of multiple TSOs in a given entry-exit system.

The exceptions are in Article 10 for multi-TSO entry-exit systems within a MS, and in Article 11 for multi-TSO entry-exit systems covering more than one MS. The exception rules distinguish along two dimensions: (1) whether the RPMs are the 'same' or 'different' types; and (2) 'joint' and 'separate' RPM application. Figure 18 shows different options under Articles 10 and 11.

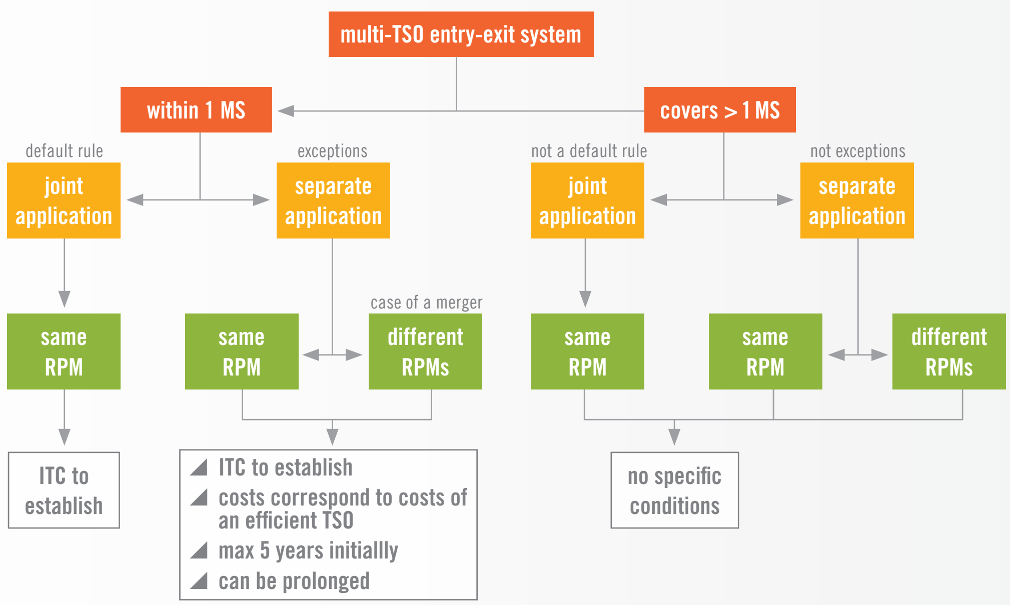


Figure 18: Multi-TSO arrangements in an entry-exit system within one MS and covering more than one MS

1) 'ITC' stands for inter-TSO compensation.

Article 10(1) sets out a default rule 'same jointly': all the TSOs jointly apply the same methodology. 'Same jointly' is consistent with the 'same' default rule in Article 6(3).

Article 10(2) foresees two exceptions from 'same jointly' subject to NRA decision and for an initial time period of five years, which the NRA may prolong:

- Article 10(2)(a) sets out the first exception 'same separately', where all TSOs apply the same RPM separately. 'Same separately' is consistent with the 'same' default rule in Article 6(3) but constitutes an exception from the 'jointly' default rule in Article 10(1).
- Article 10(2)(b) sets out the second exception 'different separately', where all TSOs apply different RPMs separately while planning to merge entry-exit systems. 'Different separately' is an exception from the 'same' default rule in Article 6(3) and from the 'jointly' default rule in Article 10(1).

Article 11 does not foresee any defaults, exceptions or specific conditions. There are three options if multi-TSO arrangements cover more than one MS: 'same jointly', 'same separately' and 'different separately'.

Conditions and process aspects for reference price methodology application in a multi-TSO entry-exit system within a Member State

Table 5 summarises the conditions for applying same/different RPMs jointly/separately in an entry-exit system within a MS.

SCENARIOS FOR MULTI-TSO ARRANGEMENTS WITHIN A MS

Scenario for multi-TSO arrangements within a MS	Conditions for scenario application
'Same jointly'	Establishment of an effective inter-TSO compensation **('ITC')** mechanism
'Same separately'	◢ Establishment of an effective ITC mechanism with the aim to: (1) prevent detrimental effects on TSOs' transmission services revenue; and (2) avoid cross-subsidies between domestic and cross-border network users ◢ Costs correspond to those of an efficient TSO ◢ Initial time period of five years which the NRA may prolong
'Different separately'	◢ Same as for 'same separately' scenario ◢ Planning of entry-exit systems merger within a MS supported by an impact assessment and cost-benefit analysis **('CBA')** ◢ Initial time period of five years which the NRA may prolong

Table 5: Scenarios for multi-TSO arrangements within a MS

All three scenarios in Table 5 require NRA consultation on the principles of an effective ITC mechanism and its consequences on the tariff level. As explained in Part 2, such a consultation must be conducted simultaneously with the final TSO/NRA consultation under Article 26(1), and with the NRA consultation on multipliers, seasonal factors and discounts under Article 27. The relevant NRA must publish the consultation responses on ITC consultation as well as the NRA decision on the ITC mechanism adopted. Per ENTSOG's estimation, publication should occur simultaneously with NRA decisions on the other two consultations[1].

For 'same separately' and 'different separately' in Table 5, the TAR NC sets out certain additional process compliance requirements not shown in the table. Under Article 10(4) the NRA can permit separate application of the RPM for an initial period of up to five years from the AD 1, which is the TAR NC's entry into force[2]. ENTSOG believes that the five-year limit could reflect the need to conduct periodic consultations under Article 26 at least every five years. As the NRA's initially allowed time period approaches expiration, the NRA may decide to extend the period, 'sufficiently in advance' of the expiration date.

What an inter-TSO compensation mechanism is

As an example, an 'A-to-B' ITC may indicate that TSO A transfers a certain amount of money directly to TSO B. TSO A should actually obtain revenues equal to the allowed revenue plus compensation for the required ITC transfer; otherwise the transfer to TSO B would jeopardise revenue recovery. Similarly, TSO B's allowed revenues should also consider the ITC transfer. The transfer reduces the revenues that TSO B will need to earn from its own capacity bookings.

Annex G provides an ITC example.

1) See Part 2 'Indicative timeline for the TAR NC implementation', Chapter II 'General timeline', Section 'Multi-TSO entry-exit systems within a MS'.

2) See Section 'Article 38 – entry into force'.

Chapter III: Reserve Prices

Chapter III 'Reserve Prices' of the TAR NC has the following structure: Articles 12 and 13 address 'general requirements' for reserve prices; Articles 14 and 15 elaborate on the calculation of 'reserve prices for firm capacity products' with or without seasonal factors; Article 16 addresses 'reserve prices for interruptible capacity products'.

Summary

Scope: IPs
Application date: 31 May 2019

Reserve prices serve as a floor in the relevant capacity auction. The previous Chapter sets out how to calculate a reference price; this Chapter addresses the next steps for defining the reserve prices: the capacity-based transmission tariffs used in the auctions.

The reserve price for firm yearly capacity is equal to the reference price. The reserve prices for firm non-yearly capacity products involve the application of formulas with **multipliers** based on the reference price and, optionally, **seasonal factors**.

Reserve price = time proportion of reference price x multiplier x seasonal factor

The TAR NC defines the ranges for the respective multipliers, and a detailed methodology for calculating seasonal factors.

- The range for quarterly and monthly multipliers is between 1 and 1.5.
- The range for daily and within-day multipliers is between 1 and 3.

The range for daily and within-day multipliers can be extended in *'duly justified cases'*. Depending on ACER's recommendation by 1 April 2021, the range for these multipliers may narrow to between 1 and 1.5 by 1 April 2023.

The same ranges apply to the arithmetic mean over the gas year of the product of each separate multiplier and its seasonal factor.

The reserve prices for interruptible capacity products involve discounts to the reserve prices for the corresponding firm capacity products. There are two alternatives for such discounts:

- An **ex-ante discount** calculated upfront, based on the formula set out in the TAR NC, using the probability of interruption and the estimated economic value of the product;
- An **ex-post discount**, which constitutes compensation paid to network users after the actual interruption has occurred; such a discount is an option only if physical congestion did not prompt any interruptions in the preceding gas year.

The multipliers, seasonal factors and discounts are subject to NRA **consultation** with adjacent NRAs and relevant stakeholders **every tariff period.**

ARTICLE 12(1) VARIABILITY OF MULTIPLIERS, SEASONAL FACTORS AND DISCOUNTS

Responsibility: subject to consultation per Article 28(1) by NRA; subject to decision by NRA

The CAM NC foresees five standard capacity products: yearly, quarterly, monthly, daily and within-day. Article 11 of the CAM NC covers the 'runtime' or start and end date of each product. Chapter III of the TAR NC addresses the calculation of reserve prices for non-yearly standard capacity products, and also discounts for all interruptible products.

Table 6 shows how non-yearly prices can vary following the TAR NC rules on multipliers, seasonal factors and interruptible discounts. The example involves only a quarterly standard capacity product, at one IP.

<table>
<tr><th colspan="3">MULTIPLIERS, SEASONAL FACTORS AND INTERRUPTIBLE DISCOUNTS FOR QUARTERLY PRODUCTS AT AN IP</th></tr>
<tr><th>Multiplier</th><th>Multiplier and seasonal factor</th><th>Multiplier and interruptible discount</th></tr>
<tr><td>Multiplier describes the pricing relationship between the short-term product and the yearly product</td><td>Seasonal factor allows for variations in the seasonal value of the same standard capacity products</td><td>Although the firm price is the same price for a given 'category' of products, there can be different interruptible prices – depending on factors Pro and A</td></tr>
<tr><td>Quarterly – the same multiplier for all four products
◢ Q1 firm 1.5
◢ Q2 firm 1.5
◢ Q3 firm 1.5
◢ Q4 firm 1.5</td><td>Quarterly – the same multiplier for all four products but different seasonal factors
Assumptions:
◢ Q1 and Q4 have 92 days, Q2 has 90 days, Q3 has 91 days
◢ Multiplier is 1.5
Initial values:
◢ Q1 firm 1.5×1.5
◢ Q2 firm 1.5×1.7
◢ Q3 firm 1.5×0.8
◢ Q4 firm 1.5×0.7
Average product:
$(1.5 \times 1.5 \times 92 + 1.5 \times 1.7 \times 90 + 1.5 \times 0.8 \times 91 + 1.5 \times 0.7 \times 92) / (92 + 90 + 91 + 92) = [1.5(1.5 \times 92 + 1.7 \times 90 + 0.8 \times 91 + 0.7 \times 92)] / 365 \approx 1.760$
Correction factor: 1.5/1.760
Corrected values:
◢ Q1 firm $1.5 \times 1.5 \times (1.5/1.760) = 1.5 \times 1.28$
◢ Q2 firm $1.5 \times 1.7 \times (1.5/1.760) = 1.5 \times 1.45$
◢ Q3 firm $1.5 \times 0.8 \times (1.5/1.760) = 1.5 \times 0.68$
◢ Q4 firm $1.5 \times 0.7 \times (1.5/1.760) = 1.5 \times 0.60$
After correction, average products falls within multiplier range:
$[1.5(1.28 \times 92 + 1.45 \times 90 + 0.68 \times 91 + 0.60 \times 92)] / 365 = 1.5$</td><td>Quarterly – the same multiplier for all four products but different probability of interruption/factor 'A'.
Assumptions:
◢ 2 products P1 and P2 with 'Pro' of 0.1 and 0.25 in Q1
◢ 2 products P3 and P4 with 'Pro' of 0.15 and 0.2 in Q2
◢ 'A' factor is 1 in Q1 and 2 in Q2, no seasonal factor at all
◢ Q1 has 92 days (d), Q2 has 90 days
◢ Reserve price (RP) for annual product is 365
◢ Multiplier is 1.5
Calculation of discount:
$Di = Pro \times A \times 100 \times RP \times (d/365) \times 1.5$
◢ Discount for P1 in Q1 = $10\% \times 1 \times 100\% \times 365 \times (92/365) \times 1.5 = 13.80$
◢ Discount for P2 in Q1 = $25\% \times 1 \times 100\% \times 365 \times (92/365) \times 1.5 = 34.50$
◢ Discount for P3 in Q2 = $15\% \times 2 \times 100\% \times 365 \times (90/365) \times 1.5 = 40.50$
◢ Discount for P4 in Q2 = $20\% \times 2 \times 100\% \times 365 \times (90/365) \times 1.5 = 54.00$</td></tr>
</table>

Table 6: Multipliers, seasonal factors and interruptible discounts for quarterly products at an IP

The TAR NC calls for the same multiplier at a given IP for the same standard capacity products. Also, the TAR NC envisages that multipliers, seasonal factors and interruptible discounts may be: (1) the same at all the IPs; or (2) the same at each group of the IPs; or (3) different at all the IPs.

SEPARATE RESERVE PRICES

ARTICLE 12(2)

Responsibility: subject to national decision regarding the tariff period

On the one hand, Article 29 requires the publication of reserve prices before the annual yearly capacity auction, for all firm and interruptible standard capacity products that cover the time period *'at least until the end of the gas year beginning after the annual yearly capacity auction'*. On the other hand, the reserve prices are set for tariff period, which has different start/end dates and duration across the EU. Therefore, the TAR NC requires the publication of binding reserve prices in June Y, which effectively requires reserve prices set for the gas year from October Y to September Y+1.

Article 12(2) clarifies the situation for such published reserve prices when the tariff period does not coincide with the gas year: for the tariff periods January–December, April–March and July–June. In such cases, the binding reserve prices are 'separate' for the time periods corresponding to two parts of the same gas year: (1) from 1 October until the end of the prevailing tariff period; and (2) from the beginning of the tariff period following the prevailing one until 30 September.

Article 12(3) foresees that published reserve prices are *'binding'* at least *'for the subsequent gas year'*. Article 29 sets out that such prices are *'applicable'* for the time period *'until at least the end of the gas year beginning after the annual yearly capacity auction'*. Figure 19 on the following page shows that for the auction in July 2018, the binding reserve prices must be published in June 2018 for the time period in pink box covering the gas year October 2018–September 2019.

- For January–December tariff period indicated in blue, the separate reserve prices cover the time period from 1 October 2018 to 31 December 2018 and the time period from 1 January 2019 to 30 September 2019.
- For April–March tariff period indicated in green, the separate reserve prices cover the time period from 1 October 2018 to 31 March 2019 and the time period from 1 April 2019 to 30 September 2019.
- For July–June tariff period indicated in orange, the separate reserve prices cover the time period from 1 October 2018 to 30 June 2019 and the time period from 1 July 2019 to 30 September 2019.
- For October–September tariff period indicated in yellow, the 'separate reserve prices' situation does not apply and the reserve prices cover the full time period from 1 October 2018 to 30 September 2019.

As for 'which prices go into the auctions' for yearly products, where 'go into' means to serve as an eligible floor in an auction, the answer is the reserve prices published for the 1st part of the gas year for tariff periods January–December, April–March and July–June. Alternatively, it could be the weighted average of the two prices: the one published for the 1st part of the gas year and the one published for the 2nd the part of the gas year.

As for the basis for calculating the payable price, where the capacity is contracted for the gas year following the annual yearly capacity auction, one needs to distinguish between whether a fixed or a floating payable price approach is applied:

- For fixed payable price approach, the reserve prices published for the 1st part of the gas year will be used for calculating the payable price.
- For the floating payable price approach, this will also be the reserve prices published for the 1st part of the gas year, but only to calculate the respective payable prices until the end of the 1st tariff period. When the 2nd tariff period starts, the reserve prices published for the 2nd part of the gas year will provide the basis for calculating the respective payable prices.

For further information, please refer to Chapter VIII 'Publication requirements'.

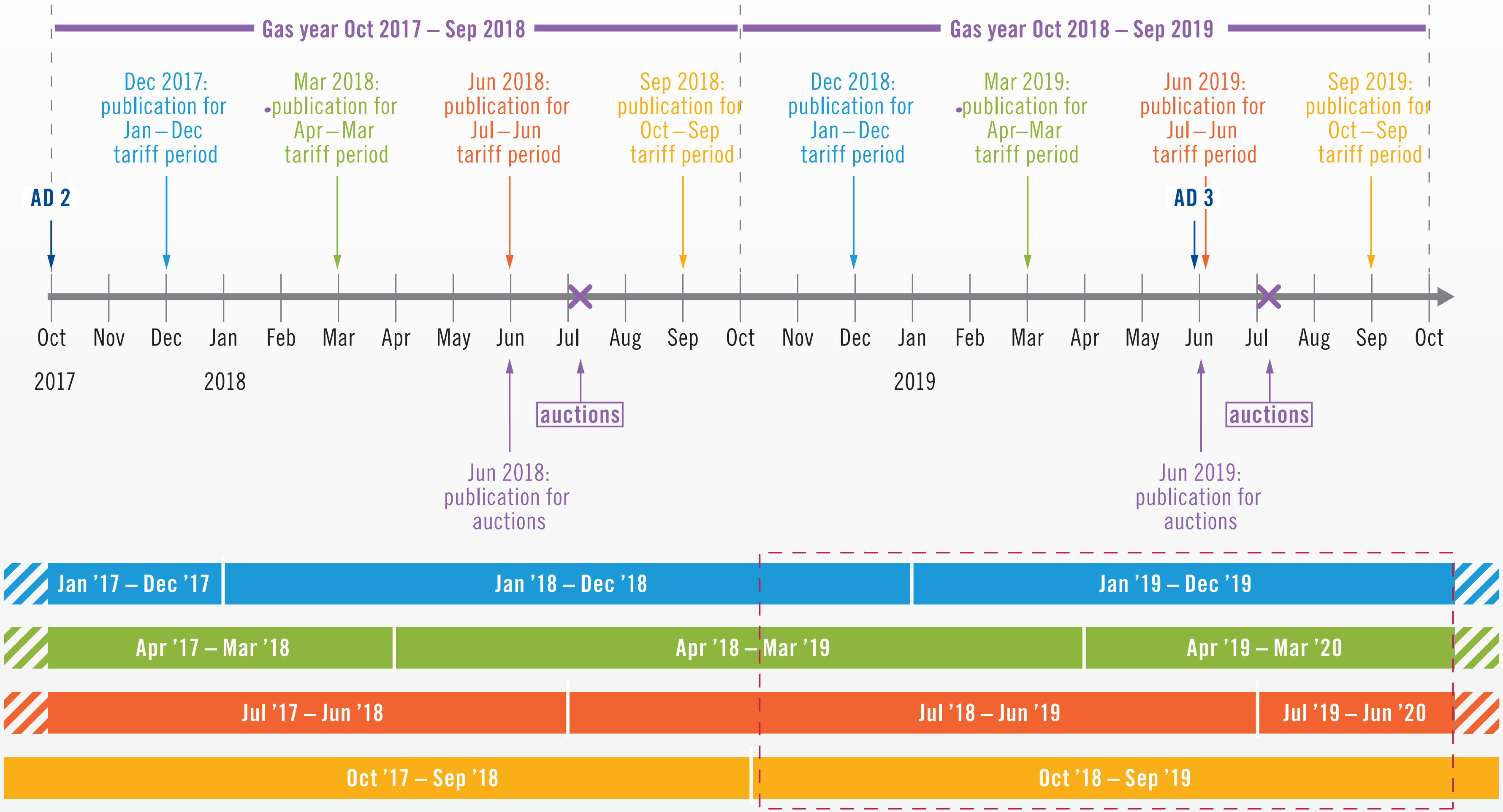


Figure 19: Separate reserve prices published in June 2018 for auctions in July 2018

BINDING RESERVE PRICES

Responsibility: update of the reserve prices within the tariff period is subject to NRA decision

Default date for annual yearly capacity auctions

As of 2018, the Amended CAM NC sets the default date of the annual yearly capacity auction as the first Monday of July, and not the first Monday of March[1]. Rescheduling from March to July should provide more time to gather the accurate information needed for calculations required for publication.

ENTSOG believes that the timing of 30 days before the annual yearly auctions strikes an appropriate balance between:

- Allowing network users enough time to plan their booking strategies;
- Providing enough time to enable tariff calculations that are as accurate as possible, and that can consider forecast contracted capacity in conjunction with estimates of under-/over-recovery from previous years.

Detrimental effect on revenue and cash flow

The TAR NC requires tariff calculations to set binding tariffs for IPs, and for non-IPs where the CAM NC applies, prior to the annual yearly capacity auctions. Compared to the current scenarios, transmission tariffs for IPs will be calculated a few months in advance. Accelerating the calculation of tariffs will reduce their accuracy, exposing the TSO to greater uncertainty regarding revenue recovery. In the recitals, the TAR NC expresses the desire to minimise TSO exposure: *'In order to promote stability of transmission tariffs for network users, to foster financial stability and to avoid detrimental effects on the revenue and cash flow positions of transmission system operators, principles for revenue reconciliation should be set out.'* The sentence covers TSOs functioning under all types of regulatory regimes, including price cap and non-price cap regimes.

Binding 'beyond the subsequent gas year' for fixed payable price approach

Article 3(23) defines a fixed payable price as a reserve price not subject to any adjustments other than indexation. A fixed payable price is consistent with Article 12, which allows the prices published in accordance with Article 29 to remain binding beyond the subsequent gas year. Anyone purchasing a yearly capacity product over consecutive years at the same time at a fixed price, pays the same reserve price indexed from one year to another for every year of the booked capacity, this is therefore the binding price. Please see Annex H for examples.

Exception: recalculation of discounts for monthly and daily interruptible products

The TAR NC permits the recalculation within a tariff period of discounts for interruptible monthly and daily standard capacity products. Recalculation can occur if the probability of interruption changes by more than 20%. The intention is not to dis-incentivise the accurate forecasting of interruptible capacity sales, but merely to provide a safeguard enabling TSOs/NRAs to adapt to changing conditions. The updated transmission tariffs are subject to NRA approval.

1) See Article 11(4) of the Amended CAM NC.

Exception: update of reference prices

The TAR NC permits recalculation of the reference price within the tariff period in exceptional cases subject to the NRA approval. Recalculation can protect the TSO if, for example, tariffs were initially calculated based on forecasted contracted capacity and on forecasted flows that significantly exceed the actual demand witnessed within the tariff period, and if the mismatch is expected to persist for the rest of the tariff period.

Other examples of 'exceptional cases' warranting a mid-period update could be exceptionally mild winter or legal changes, such as new legislation or a court decision.

ARTICLE 13 LEVEL OF MULTIPLIERS AND SEASONAL FACTORS

Responsibility: subject to consultation per Article 28(1) by NRA; subject to decision by NRA

General

The multipliers must fall within the ranges as shown in Figure 20. Where seasonal factors are applied, the same range should bind the arithmetic mean of the product of the respective multiplier and individual seasonal factors (M x SF) over the gas year.

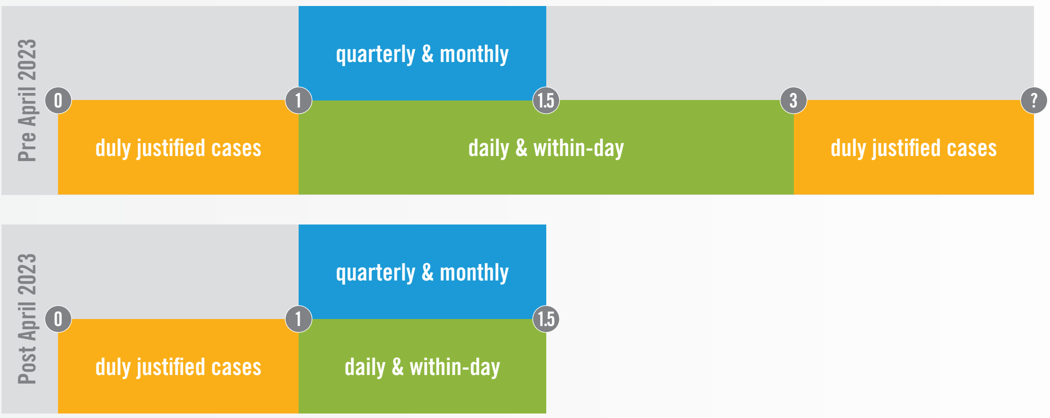


Figure 20: Level of multipliers and seasonal factors

Below are sections dedicated to Articles 14 and 15, explaining how to calculate reserve prices without and with seasonal factors.

Situation before April 2023

The TAR NC permits quarterly and monthly multipliers of between 1 and 1.5 inclusive, that is including exactly 1 and exactly 1.5.

There is more flexibility as to daily and within-day multipliers. The default rule allows such multipliers to range from 1 to 3 inclusive. The TAR NC allows for widening such ranges in 'duly justified cases':

- The floor can range from 0 to 1 exclusive, that is excluding either 0 or 1;
- The cap can be more than 3 with no specific limit.

As for the first bullet point, ENTSOG views that multipliers less than 1 are consistent with the economic principle of the efficiency of marginal cost pricing, in this instance the short run marginal cost of making capacity available on a daily or within-day basis. Such multipliers can encourage the short-term efficient use of the transmission system, and can facilitate short-term trading, improving market liquidity. When considering such multipliers, the NRA may balance the promotion of short-term gas trades against the need for long-term capacity bookings that provide efficient investment signals. The NRA must also consider the risk of cross-subsidising particular network users if a large proportion switch to non-yearly discounted products to reduce their contribution to the recovery of some network costs.

As for the second bullet point, ENTSOG considers that a duly justified case could involve the high utilisation of within-day capacity. Hourly tariffs for within-day capacity can create an incentive to book within-day capacity instead of daily capacity. For example, in systems that market capacity hourly in terms of kWh/h, network users active at IPs could cut their costs at the expense of other network users. Within-day capacity could warrant a higher multiplier than 3 to avoid the problem. Another example could involve a price cap regime where it is necessary to achieve a specific balance between short-term and long-term bookings.

Situation after April 2023

The TAR NC does not indicate any change in the ranges for quarterly and monthly multipliers after April 2023. They should remain as set out above.

In contrast, ACER can make a recommendation by 1 April 2021 to cap the multipliers for daily and within-day standard capacity products at 1.5 by 1 April 2023. The recommendation must take into account the following aspects related to the use of multipliers and seasonal factors before and as from the AD of 31 May 2019 for the TAR NC Chapter III 'Reserve prices':

- Changes in booking behaviour;
- Impact on the transmission services revenue and its recovery;
- Differences between the level of transmission tariffs applicable for two consecutive tariff periods;
- Cross-subsidisation between network users having contracted yearly and non-yearly standard capacity products;
- Impact on cross-border flows.

Absent specific mention of the 'floor' for daily and within-day multipliers, it is reasonable to conclude that the above exception regarding 'duly justified cases' still applies, permitting a range from 0 to 1 exclusive.

For further details regarding the impact of low multipliers on reference price levels, please refer to Annex I.

Reserve Prices for Firm Capacity Products

ARTICLE 14 CALCULATION OF RESERVE PRICES

Responsibility: the level of calculated reserve prices is subject to consultation per Article 28(1) by NRA; subject to decision by NRA

General

The TAR NC provides general formulas for reserve prices for non-yearly products without seasonal factors. The formulas distinguish between within-day and non-within-day products. Non-within-day products must have reserve prices based on the number of days in the product, while within-day products must have reserve prices based on the number of hours.

How to calculate reserve prices for firm non-yearly standard capacity products without seasonal factors

For quarterly, monthly and daily firm standard capacity products, the formulas for calculating reserve prices are:

$$P_{st} = m_i \times (p_y/365) \times d$$

where:

i represents the non-yearly product: quarterly, monthly or daily capacity product,

P_{st} is price of a short-term product of a duration of 'd' days,

m_i is the multiplier corresponding to the standard product (m_Q, m_m or m_D),

p_y is price of yearly product,

d is duration of short-term product in days,

For leap years, $P_{st} = m_i \times (p_y/366) \times d$

For within-day firm standard capacity products, the formula for calculating reserve prices is:

$$P_{st} = m_{WD} \times (p_y/8760) \times h$$

where:

P_{st} is price of a short-term product of a duration of 'h' hours,

m_{WD} is the multiplier corresponding to within-day products,

p_y is price of yearly product,

h is duration in remaining hours of the gas day

For leap years, $P_{st} = m_{WD} \times (p_y/8784) \times h$

One of the components of the mathematical formula is ‘d’ for the duration of the different non-yearly products in days. The table below shows the number of days that make up the yearly, quarterly and monthly products.

NUMBER OF DAYS FOR THE STANDARD CAPACITY PRODUCTS		
Yearly	**Quarterly**	**Monthly**
365 (or 366) [1)]	Q1 = Oct – Dec = 92	Oct = 31
		Nov = 30
		Dec = 31
	Q2 = Jan – Mar = 90 (or 91) [1)]	Jan = 31
		Feb = 28 (or 29) [1)]
		Mar = 31
	Q3 = Apr – Jun = 91	Apr = 30
		May = 31
		Jun = 30
	Q4 = Jul – Sep = 92	Jul = 31
		Aug = 31
		Sep = 30

Table 7: Number of days for the standard capacity products

For further details, please see Annex J.

Within-day capacity priced as daily capacity

Currently ‘within-day’ capacity is sold as a daily or rest-of-the-day product, with either a daily price or an hourly price. The TAR NC does not allow for ‘within-day priced as daily’. Instead, within-day product pricing depends on the number of remaining hours in the day, as per Article 14(b).

1) 29 days in February, 91 days in Q2 of the gas year and 366 days for a leap year.

ARTICLE 15 SEASONAL FACTORS METHODOLOGY

Responsibility: the level of seasonal factors and the calculations per methodology are subject to consultation per Article 28(1) by NRA; subject to decision by NRA

General

Seasonal factors can be applied in addition to the multiplier to calculate reserve prices for non-yearly products. The purpose of seasonal factors is to foster efficient system use by allowing higher reserve prices in months with high utilisation rates, and lower reserve prices in low-utilisation months. ENTSOG considers that such pricing: (1) provides incentives to shift gas flows away from high demand periods; (2) reduces the negative impact that profiled capacity bookings may have on revenue and tariff stability; and (3) avoids additional unnecessary investment, by encouraging network use in summer and discouraging it in winter.

The TAR NC methodology to calculate seasonal factors considers the monthly utilisation rates of the transmission system. Different options exist for seasonal factors: TSOs can apply the same set of seasonal factors to all IPs, the same set of seasonal factors to a group of IPs, or a different set of seasonal factors per IP. TSOs will evaluate which approach is more appropriate to foster efficient use of the system.

Following the Article 15 methodology for calculating seasonal factors, the 12 seasonal factors for monthly products provide the basis for calculating the seasonal factors for the other three capacity products: quarterly, daily and within-day. Therefore, there are four seasonal factors for quarterly products; 12 seasonal factors for monthly products, 12 seasonal factors for daily products and 12 seasonal factors for within-day products. The seasonal factors of all quarterly products are different, the seasonal factors for all daily products of a given month are the same, and the seasonal factors for all within-day products of a given day in a given month are the same.

For a description of the detailed steps in the seasonal factors methodology, please see Annex L.

Seasonal factors methodology based on gas flows or contracted capacity

Article 15(2) stipulates that the methodology for calculating seasonal factors must consider forecasted gas flows, unless the gas flow for at least one month is 0. In such a case, the methodology should be based on contracted capacity.

Seasonal factors are corrective factors based on a multiplicative formula applied on flows. It is logical to apply higher factors when demand is high, because that is when the network capacity is most used.

How to calculate reserve prices for firm non-yearly standard capacity products with seasonal factors

Reserve prices for non-yearly products may be calculated using seasonal factors applied on top of the designated multiplier. The mathematical formula for non-yearly reserve prices with seasonal factors is similar to the previous formulas, including the seasonal factor (sf), as set out below:

For quarterly, monthly and daily firm standard capacity products, the formulas for calculating reserve prices are:

$$P_{st} = (m_i \times sf_i) \times (p_y/365) \times d$$

where:

sf_i is the seasonal factor corresponding to the given quarter, month or day (s_{fQ}, s_{fM} or s_{fD})

For leap years, $P_{st} = (m_i \times sf_i) \times (p_y/366) \times d$.

For within-day firm standard capacity products, the formula for calculating reserve prices is:

$$P_{st} = (m_{WD} \times sf_{WD}) \times (p_y/8760) \times h$$

where:

sf_{WD} is the seasonal factor corresponding to the period of the year in which the within-day product is booked

For leap years, $P_{st} = (m_{WD} \times sf_{WD}) \times (p_y/8784) \times h$.

For further details, please also see Annexes K, L and M.

Reserve Prices for Interruptible Capacity Products

ARTICLE 16 INTERRUPTIBLE DISCOUNTS

Responsibility: the level of discounts is subject to consultation per Article 28(1) by NRA; subject to decision by NRA

General

Article 16 requires the calculation of reserve prices for standard interruptible capacity products by applying a discount to the reserve prices for the corresponding standard firm capacity products. Discounts can be **ex-ante** or **ex-post**:

- An ex-ante discount involves an upfront calculation based on the probability of interruption and the estimated economic value of the product. An ex-ante discount provides a reserve price for a standard interruptible capacity product.
- An ex-post discount compensates network users in the event of interruption. Ex-post discounts can only apply to IPs where physical congestion did not prompt any interruption of capacity in the preceding gas year. The application of an ex-post discount replaces an ex-ante discount to the reserve price for a standard interruptible capacity product. With an ex-post discount, the reserve price for interruptible product should be the same as the reserve price for a firm product of an equivalent duration.

As of March 2017, the majority of the EU TSOs offer ex-ante discount. Ex-post discounts are offered in Austria, the Czech Republic, Hungary, Poland, Romania and Slovakia.

It is not possible to combine ex-ante and ex-post discounts for the same interruptible product at the same IP. The formulas for calculating ex-ante and ex-post discounts are set out below.

The level of the ex-ante and ex-post discounts is subject to NRA approval in accordance with the process outlined in Article 28.

Ex-ante approach – how to calculate discounts

The TAR NC sets the ex-ante discount for standard interruptible capacity products proportional to the probability of interruption 'Pro' and the adjustment factor 'A', calculated in accordance with the following formula:

$$Di_{ex\text{-}ante} = Pro \times A \times 100\,\%$$

Where:

$Di_{ex\text{-}ante}$ is the level of an ex-ante discount;

Pro factor is the probability of interruption which refers to the type of standard interruptible capacity product;

A is the adjustment factor applied to reflect the estimated economic value of the type of standard interruptible capacity product, calculated for each, some or all IPs, which shall be no less than 1.

The TAR NC states that the discount *'may be'* different at different IPs. The discount can therefore be the same at all IPs, at some IPs, or it can differ from one IP to another.

Pro factor

'Pro' is the probability of interruption, calculated in accordance with the following formula:

$$\mathbf{Pro} = \frac{N \times D_{int}}{D} \times \frac{CAP_{av.int}}{CAP}$$

Where:

N	is the expectation of the number of interruptions over D;
D_{int}	is the average duration of the expected interruptions expressed in hours;
D	is the total duration in hours of the respective type of standard interruptible capacity product;
$CAP_{av.int}$	is, for each interruption, the expected average amount of interrupted capacity related to the respective type of standard interruptible product;
CAP	is the total amount of interruptible capacity for the respective type of standard capacity product for interruptible capacity.

The detail in the above formula seeks to improve transparency by specifying all components. The TAR NC envisages separate calculation of the Pro factor for every type of standard interruptible capacity product offered. The CAM NC establishes five categories of standard capacity products: yearly, quarterly, monthly, daily and within-day. For interruptible capacity, the TAR NC deals with 'types' within the same category of standard capacity product. Various 'types' of products differ in their probability of interruption[1)]. Such types can be the same at all IPs, at some IPs, or they can differ from one IP to another.

'A' factor

An adjustment factor 'A' applies to reflect the estimated economic value of the type of standard interruptible capacity product. In practice, it reflects that the costs of hedging interruption for a network user are higher than the probability of interruption. Therefore, factor 'A' should help to increase the ex-ante discount if needed to reflect the actual value of the capacity.

As with the Pro factor, the TAR NC contemplates separate calculation of the 'A' factor for every type of standard interruptible capacity product offered. If the economic value of such products is the same then the level of the A factor can be the same. In addition, the TAR NC permits the calculation of the 'A' factor for each, some or all IPs. The 'A' factor can be the same at all IPs, at some IPs, or it can differ from one IP to another.

Please see Annex N for an example of an ex-ante discount for a given monthly standard interruptible capacity product.

---

1) For example, there can be two yearly interruptible capacity products offered one with the probability of interruption 0.2 and the other with the probability of interruption 0.4.

Ex-ante approach – how to calculate reserve prices

When an ex-ante discount applies, the reserve prices of standard interruptible capacity products are calculated by applying the difference between 100 % and the ex-ante discount to the reserve price of the equivalent standard firm capacity product.

Although not explicitly stated by the TAR NC, the following formulas apply to calculate the reserve price of a standard interruptible capacity product:

For yearly standard interruptible capacity product:

$$P_{int} = (1 - Di_{ex\text{–}ante}) \times T$$

Where:

P_{INT} is the reserve price for yearly standard interruptible capacity product;

$Di_{ex\text{-}ante}$ is the ex-ante discount of the product;

T is the reserve price for yearly firm capacity product.

For daily, monthly and quarterly standard interruptible capacity product:

$$P_{int} = (1 - Di_{ex\text{–}ante}) \times ((M \times S \times T/365) \times D$$

Where:

P_{INT} is the reserve price for daily, monthly or quarterly standard interruptible capacity product;

$Di_{ex\text{-}ante}$ is the ex-ante discount of the product;

M is the level of the multiplier corresponding to the respective standard capacity product;

S is the level of seasonal factor corresponding to the respective standard capacity product, if any;

T is the reserve price for yearly firm capacity product;

D is the duration of the respective standard capacity product expressed in gas days.

For leap years, the formula shall be adjusted so that the figure 365 is substituted with the figure 366.

For within-day standard interruptible capacity product:

$$P_{int} = (1 - Di_{ex\text{–}ante}) \times ((M \times S \times T/8760) \times H$$

Where:

P_{INT} is the reserve price for within-day standard interruptible capacity product;

$Di_{ex\text{-}ante}$ is the ex-ante discount of the product;

M is the level of the corresponding multiplier;

S is the level of the corresponding seasonal factor, if any;

T is the reserve price for yearly firm capacity product;

H is the duration of the within-day standard capacity product expressed in hours.

For leap years, the formula shall be adjusted so that the figure 8760 is substituted with the figure 8784.

Please see Annex N for an example of a calculation of the reserve price for a monthly standard interruptible capacity product.

Ex-post approach – how to calculate discounts

If the NRA decides to apply an ex-post discount, it must be equal to three times the reserve price for daily standard firm capacity products, irrespective of which capacity product is contracted and actually interrupted. Article 16(4) does not prevent the NRAs from taking account of the capacity that was actually interrupted and determining a cap on the reimbursement amount.

Please see Annex N for an example of an ex-post discount.

Non-physical backhaul capacity

'Non-physical backhaul' means that at unidirectional entry or exit points the volume of gas is nominated to flow in the opposite direction to the physical flow. TSOs offer firm capacity only in one direction, and the capacity offered in the other direction is interruptible, non-physical backhaul.

Article 16 describes the methodology for pricing interruptible capacity products, which applies to all standard interruptible capacity products regardless of the direction of the gas flow at a given IP. ENTSOG believes that non-physical backhaul capacity is an interruptible product, priced as set out in the TAR NC.

Chapter IV: Reconciliation of Revenue

Chapter IV 'Reconciliation of Revenue' of the TAR NC is structured as follows: Articles 17 and 18 address 'general' principles outlined in the Chapter; Articles 19 and 20 set out the 'revenue reconciliation' rules.

Image courtesy of Gascade

Summary

Scope: IPs and non-IPs
Application date: 31 May 2019

This Chapter sets the requirements for reconciling **transmission services revenue.** However, these requirements may also apply to **non-transmission services revenue,** subject to the consultation and approval per Chapter VII 'Consultation requirements'.

The rules in this Chapter include the **principles** of revenue reconciliation, the calculation of **under-/over-recovery,** the rule of having only **one regulatory account** per TSO, and the basic requirements for its reconciliation.

Most of the Chapter only applies to a **non-price cap regime.** The only rule that also applies to a **price cap regime** involves the use of the auction premium to invest in reducing physical congestion.

General

ARTICLE 17 GENERAL PROVISIONS

Responsibility: no implications for TSO/NRA responsibility

General

The TAR NC clarifies which rules of this Chapter apply under different regulatory regimes:

- All the rules of the Chapter apply if a TSO functions only under non-price cap regime.
- If a TSO functions only under a price cap regime, then only three rules apply: (1) Article 17(2) on addressing a TSO's risk; (2) Article 17(3) on the possible extension of the scope of the Chapter to non-transmission services; and (3) Article 19(5) on the treatment of the auction premium. The rest of the Chapter does not apply, including the specific terms for 'revenue reconciliation', 'regulatory account' and 'under-/over-recovery'.
- If a TSO functions under a combination of non-price cap and price cap regimes, then the respective rules apply for the respective shares of the TSO assets.

Principles of revenue reconciliation

For a non-price cap regime, the three principles for revenue reconciliation are: minimising the under-/over-recovery of the transmission services revenue, ensuring that transmission tariffs recover revenues *'in a timely manner'*, and avoiding significant differences between transmission tariffs in consecutive tariff periods *'to the extent possible'*.

The above principles do not apply when a TSO: (1) functions under a price-cap regime; and (2) offers a fixed payable price approach, regardless of the applicable regulatory regime.

How to use the Chapter for non-transmission services

Chapter IV applies to transmission services by default, and therefore to transmission services revenue and transmission tariffs. All the rules of the Chapter 'work' only for one part of the TSO services.

However, Article 17(3) provides the option of extending such rules also to non-transmission services, *'mutatis mutandis'*. The TAR NC is silent on how exactly to customise the rules for extension to non-transmission services revenue. Instead, there is an obligation – as part of the periodic consultation set out in Article 26 – to consult on the way to reconcile non-transmission services revenue. In any case, the principles established by Article 13 of the Gas Regulation apply.

As explained below, TSOs can have only one regulatory account. Following Article 17(3), these are possible approaches for non-transmission services reconciliation that need further investigation:

- If the non-transmission services revenue is reconciled under the Chapter's rules, then the TSO must log the under-/over-recovery from such services onto the one regulatory account. There are two suggestions:
  - One regulatory account should be split into sub-accounts for recording and reconciling the under-/over-recovery from transmission services and, separately, from non-transmission services. 'Sub-accounts' are an option under Article 30(1)(b)(vi) where and to the extent that the TSO functions under a non-price cap regime.
  - One regulatory account is used for recording and reconciling together the under-/over-recovery from transmission services and from non-transmission services. This is the current approach in Germany and in France.
- In case the non-transmission services revenue is reconciled pursuant to other rules than under the Chapter, the under-/over-recovery from such services may logged on to some other account than 'one regulatory account'. Great Britain currently follows this approach.

The approaches described above are ENTSOG's examples of what could be done. The NRA must decide how to reconcile non-transmission services revenue in a given system. Article 19(2) permits the NRA to enact *'other rules'* in accordance with the Gas Directive.

UNDER-/OVER-RECOVERY — ARTICLE 18

Responsibility: no implications for TSO/NRA responsibility

Article 18 addresses under-/over-recovery of the value of the allowed revenue for a given tariff period. The under-/over-recovery is calculated not for all the TSO's allowed revenue but only for the portion corresponding to the provision of transmission services.

The under-/over-recovery is the difference between: (1) the amount R which represents the allowed transmission services revenue; and (2) the amount R_A which is actually collected revenue by the TSO. Both R and R_A must relate to the same tariff period. If the difference $R_A – R$ is positive, there is an over-recovery. If the difference is negative, there is an under-recovery.

When calculating the under-/over-recovery of a given TSO, the ITC payments have to be taken into account in multi-TSO entry-exit systems within a MS.

Revenue Reconciliation

ARTICLE 19(1), 19(2) AND 19(4)

REGULATORY ACCOUNT

Responsibility: the attribution of under-/over-recovery to the regulatory account is subject to NRA decision

Characteristics of the regulatory account

A regulatory account records the difference between the TSO's allowed revenues and the revenues actually obtained during the same time period. The regulatory account must therefore include information on the differences between forecasted contracted capacity and actual capacity sales. The regulatory account will be reconciled by forwarding the resulting balance to the transmission services revenue being part of the allowed revenue for the next relevant time period. The concept of 'revenue reconciliation period' is explained below.

The TAR NC requires each TSO functioning under a non-price cap regime to have one regulatory account recording the information on under-/over-recovery. The NRA can decide to require aggregated information, or information differentiated by source/aim showing the gap for each item.

Other information in the regulatory account

As described above, the regulatory account reports the difference between the allowed and the actual revenues. In addition the NRA can require the regulatory account to also include 'other information' as set out in Article 19(1), as the parameters set at the beginning of the regulatory period may be subject to change. Depending on the applicable regulatory regime, examples are:

- Parameters entering into the definition of the weighted average cost of capital (WACC): risk free rate and/or debt/equity ratio (e.g. Austria, Belgium, GreatBritain, Ireland, Lithuania, Romania);
- Operational expenditures (OPEX): depending on the possible incentive mechanisms or efficiency targets in place, or not, the difference between the forecasted OPEX used for the tariff set-up and the actual OPEX can go fully or partially into the regulatory account (e.g. Belgium, Great Britain, Greece, Ireland, Lithuania, Romania);
- Variable costs such as energy (e.g. Austria, Belgium, Bulgaria, the Czech Republic, France, Germany, Great Britain, Ireland, Lithuania, the Netherlands, Romania);
- CO_2 certificate costs (e.g. Austria, Belgium, Bulgaria, France, Germany, Great Britain, Ireland, Romania);
- Inflation indices: differences between forecasted values and actual values (e.g. Belgium, Bulgaria, France, Great Britain, Ireland, Lithuania, Romania);
- Capital expenditures (CAPEX): in case the budgeted value of the foreseen investments differ from the actual values (e.g. Austria, Belgium, Bulgaria, the Czech Republic, France, Germany, Great Britain, Greece, Ireland, Lithuania, Romania);
- Depreciations: difference in depreciation amounts between forecasted and actual values (e.g. Austria, Belgium, Bulgaria, the Czech Republic, France, Great Britain, Greece, Ireland, Lithuania, Romania);
- Interest rate: difference between forecasted and actual rates on the amount of the regulatory account (e.g. Belgium).

One regulatory account

From the TSO's perspective, having one regulatory account instead of several addresses the overall financial viability and stability of the TSO rather than the financial performance of each specific source of revenue recovery, such as revenues from entry points and from exit points, from new infrastructure and from old infrastructure.

From the perspective of network users, having one regulatory account, which implicitly attributes under-/over-recovery to all entry and exit points for all the transmission tariffs, effectively minimises the impact on prospective changes to transmission tariff levels.

As explained above, it is suggested that the one regulatory account may be split into sub-accounts with the aim of avoiding undue cross-subsidisation when reconciling non-transmission services revenue.

REGULATORY ACCOUNT AND INCENTIVE MECHANISMS

ARTICLE 19(3)

Responsibility: subject to NRA decision

The TAR NC envisages that if incentive mechanisms are set for capacity sales, then only a part of the under-/over-recovery must be logged on to the regulatory account. An example of a 'positive' incentive mechanism is a NRA decision to allow the TSO to keep a portion of over-recovery stemming from capacity sales at certain points. Retaining a portion of over-recovery implies withholding a portion from the regulatory account. The same principle applies if an incentive mechanism entails a penalty for the TSO; an effective penalty implies withholding from the regulatory account. In other words, the portion of under-/over-recovery not logged on to the regulatory account is *'kept or paid by the TSO'* which means that the TSO pays the portion of the deficit due to the under-recovery and keeps the earned portion of profit due to the over-recovery.

ARTICLE 19(5) AUCTION PREMIUM

Responsibility: subject to NRA decision

Difference between the regulatory account and 'specific separate account'

Article 19(1)–(4) refers to a regulatory account that has a different use than the *'specific separate account'* referred to in Article 19(5) for any earned auction premium.

The regulatory account is for monitoring any under-/over-recovery of the TSO's transmission services revenue, and limiting its financial exposure or reimbursing any excess recovery to users. In contrast, a specific separate account for an auction premium facilitates monitoring the TSO's revenue collected from the marginal price a network user is willing to pay in addition to the reserve price.

Use of auction premium

A TSO may attribute an auction premium to a specific account separate from the regulatory account. Alternatively, the auction premium may be attributed to the regulatory account, in which case it will affect future transmission tariffs.

The NRA can decide how to use the auction premium. Table 8 shows options that depend on the applicable regulatory regime.

USE OF AUCTION PREMIUM IN DIFFERENT REGULATORY REGIMES		
Use of auction premium/Regulatory regime	**Non-price cap**	**Price cap**
Reduce physical congestion	Yes	Yes
Decrease transmission tariffs	Yes	No

Table 8: Use of auction premium in different regulatory regimes

ARTICLE 20 RECONCILIATION OF REGULATORY ACCOUNT

Responsibility: subject to NRA decision

Reconciliation via a reference price methodology

As explained above, the TSO must determine annually for the last completed tariff period the difference between the allowed transmission services revenue and the transmission services revenue actually collected by the TSO. The TSO must log all of the positive or negative deviation onto the regulatory account, or just a portion in the presence of incentive schemes or a decision by the NRA to use the auction premium to reduce physical congestion.

After logging some/all of the under-/over-recovery onto the regulatory account, the reconciliation entails an adjustment to the future allowed revenue. The 'adjusted' transmission services revenue then becomes an input to the applied RPM affecting the level of transmission tariffs applicable for future tariff periods. An under-recovery raises transmission tariffs while an over-recovery reduces them subject to the principle of avoiding *'significant differences between transmission tariffs in consecutive tariff periods'*.

The word 'future' above is general, since the reconciliation takes place over 'revenue reconciliation period' which may not necessarily coincide with a given tariff or regulatory period. The NRA must decide upon the appropriate reconciliation period. An under-recovery in tariff period 1 does not necessarily imply an increase to the tariff immediately or solely for tariff period 2, as the NRA's selected reconciliation period may be longer than a tariff period, spreading the under-recovery over several tariff periods.

Reconciliation via a reference price methodology and a complementary revenue recovery charge

Reconciliation of the regulatory account through use of the applied RPM is an ex-post process. The TAR NC foresees an option to apply a CRRC at non-IPs. The example below shows how to use such an option.

The only current approach is in Great Britain where capacity-based transmission tariffs are set before the tariff period, assuming that all technical capacity will be contracted. Since the actually contracted capacity never coincides with the technical capacity, the CRRC is then adjusted within the tariff period in order to mitigate any future under-recovery. The CRRC can be set to zero if there is no under-recovery in future.

Figure 21 shows the process of revenue reconciliation.

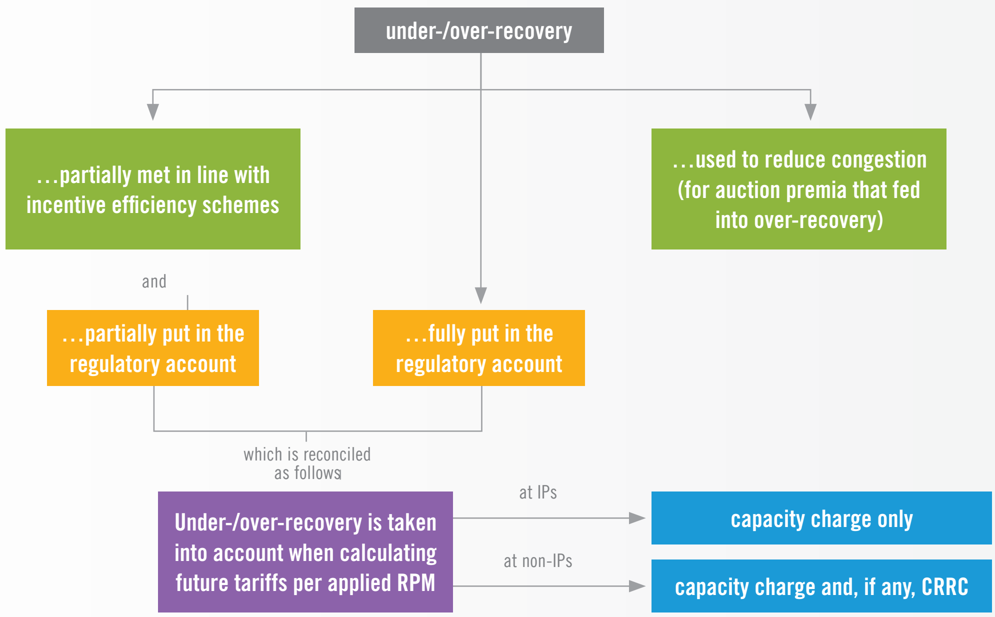


Figure 21: Process of revenue reconciliation

Chapter V: Pricing of Bundled Capacity and Capacity at VIPs

Chapter V 'Pricing of Bundled Capacity and Capacity at VIPs' of the TAR NC is structured as follows: Article 21 sets out the calculation of 'reserve prices for bundled capacity' products; Article 22 discusses the calculation of 'reserve prices for capacity products offered at a VIP'.


Image courtesy of Snam Rete Gas

Summary

Scope: IPs

Application date: entry into force (6 April 2017)

A **bundled reserve price** is the sum of entry and exit reserve prices of bundled capacity products. This Chapter outlines the rules for allocating the sales revenue between TSOs, from both the bundled reserve price and any associated auction premium.

This Chapter also addresses the calculation of a **VIP reserve price.** There are two approaches considered, depending on the applicable RPM.

Reserve Prices for Bundled Capacity Products

ARTICLE 21 BUNDLED CAPACITY

Responsibility: the agreement of TSOs regarding the split of auction premium from bundled capacity sales is subject to the approval of NRA(s)

Concept of bundled capacity and bundled reserve price

According to the Amended CAM NC, bundled capacity describes a standard capacity product offered on a firm basis, which consists of corresponding entry and exit capacity at both sides of every IP. Bundled capacity puts together or 'bundles' the two standard capacity products of the same duration at either side of an IP. Figure 22 shows the concept of bundled capacity:

- Each product offered includes the same amount of capacity on both sides of the IP;
- Capacities are contracted through a single allocation procedure via a booking platform;
- Capacities are allocated to the same network user on both sides of the IP;
- The network user nevertheless signs two contracts, one with each TSO.

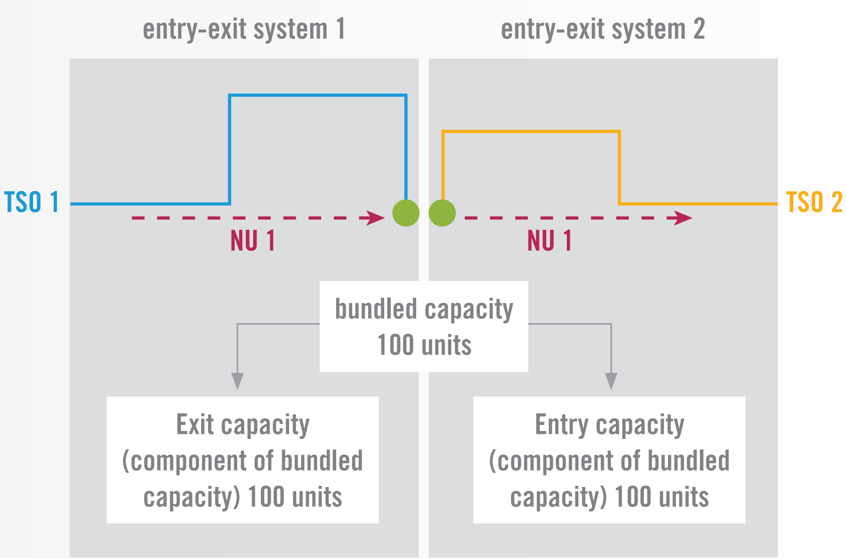


Figure 22: The concept of bundled capacity

Figure 23 shows the components of the reserve price for a bundled standard capacity product. The reserve price is equal to the sum of the reserve prices for the capacities contributing to the bundle. The constituent reserve prices do not necessarily need to be identical.

Figure 23: Components of bundled reserve price

Split of revenue from bundled capacity sales

Figure 24 shows that the revenue originating from the sale of a bundled capacity product is the sum of its bundled reserve price plus the possible auction premium.

Figure 24: Revenue from bundled capacity sales

The revenue from the bundled reserve price must be split in proportion of the reserve prices for the capacities contributing to the bundle. Each TSO will receive the revenue from the reserve price for the capacity that each TSO contributes to the bundle.

Any auction premium must be attributed to the contributing TSOs according to their agreement subject to the approval of NRA(s). The approval must be granted no later than three months before the start of the annual yearly capacity auctions.

A default rule exists for the split of the auction premium from bundled capacity sales, to avoid invoicing problems that could arise if auctions occur in the absence of approved agreements. In such cases TSOs must split the auction premiums equally.

In summary, each TSO contributing to bundled capacity receives the revenue:

(1) from the bundled reserve price proportionally to the reserve price of its contributing capacity; and

(2) a portion of any auction premium as agreed with the other TSO and approved by the NRA. In the absence of the approval of NRA(s), the portion is 50 %.

Reserve Prices for Capacity Products offered at a VIP

ARTICLE 22 VIP

Responsibility: the RPM is subject to consultation per Article 26(1) by TSO/NRA, as NRA decides (VIP reserve price is linked to RPM); subject to decision by NRA

Concept of a VIP

As defined in Article 3(23) of the Amended CAM NC[1)], a VIP is an entry and/or exit point that results from the aggregation of two or more IPs that connect the same two adjacent entry-exit systems for the purposes of providing a single capacity service. Figure 25 shows an example of a simple VIP.

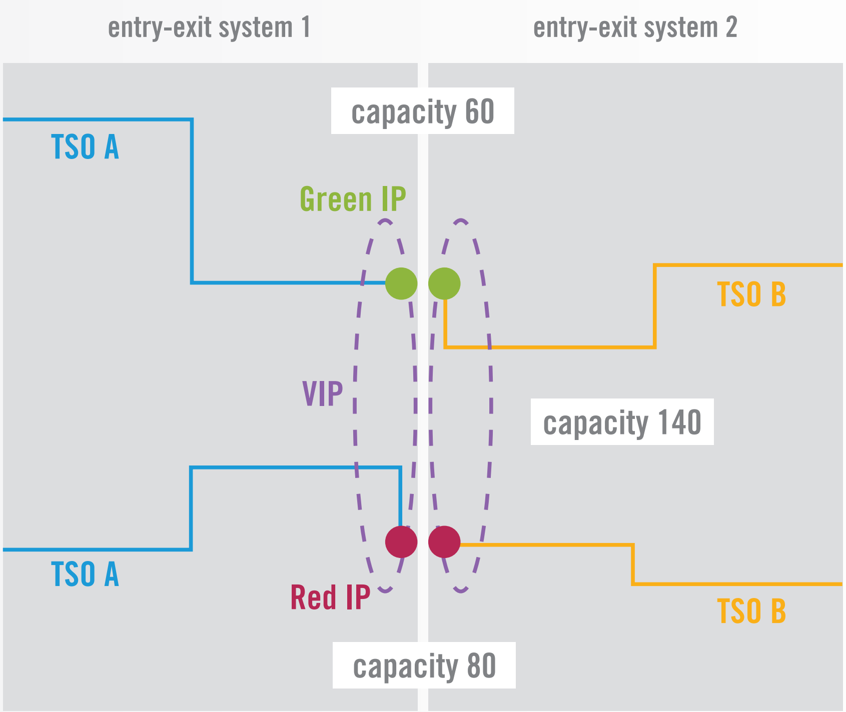


Figure 25: A concept of the VIP

According to the Amended CAM NC, where more than one IP connects two adjacent entry-exit systems, the TSOs involved must establish a VIP no later than 1 November 2018. When establishing a VIP, TSOs must ensure that its total technical capacity is equal to or higher than the sum of the technical capacities at each of the IPs contributing to the VIP. Additionally, the VIP must facilitate economic and efficient use of the system.

1) The VIP definition in the Amended CAM NC is equivalent to the VIP definition in the Old CAM NC.

Determination of the reserve price at a VIP

Two approaches can be used to calculate reserve prices for unbundled capacity products offered at a VIP:

- If the RPM considers the VIP as one network point, then the reference price at the VIP will come from running the model with that RPM, which coincides with the reserve price for the yearly product offered.
- If the RPM does not take into account the VIP as a network point in the model, then the reference price at the VIP must be obtained by combining the reference prices of each of the physical IPs that constitute the VIP, weighted by the corresponding technical or forecasted capacities as relevant. The reserve price for the yearly product is:

$$P_{st,\ VIP} = \frac{\sum_i^n (P_{st,\ i} \times CAP_i)}{\sum_i^n CAP_i}$$

$P_{st,\ VIP}$ is the reserve price for a given unbundled standard capacity product at the VIP;

i is an IP contributing to the VIP;

n is the number of IPs contributing to the VIP;

$P_{st,i}$ is the reserve price for a given unbundled standard capacity product at IP 'i' ;

CAP_i is technical or forecasted contracted capacity, as relevant, at IP 'i'.

For the Scenario shown in Figure 25, the tariff for the VIP combining the Red and the Green IP on the side of TSO A is calculated as follows:

$$P = \frac{60 \times 1.4\ €/(MWh/d) + 80 \times 1.0\ €/(MWh/d)}{60 + 80} = 1.17\ €/(MWh/d)$$

The following Figure 26 shows the process for establishing a VIP reserve price:

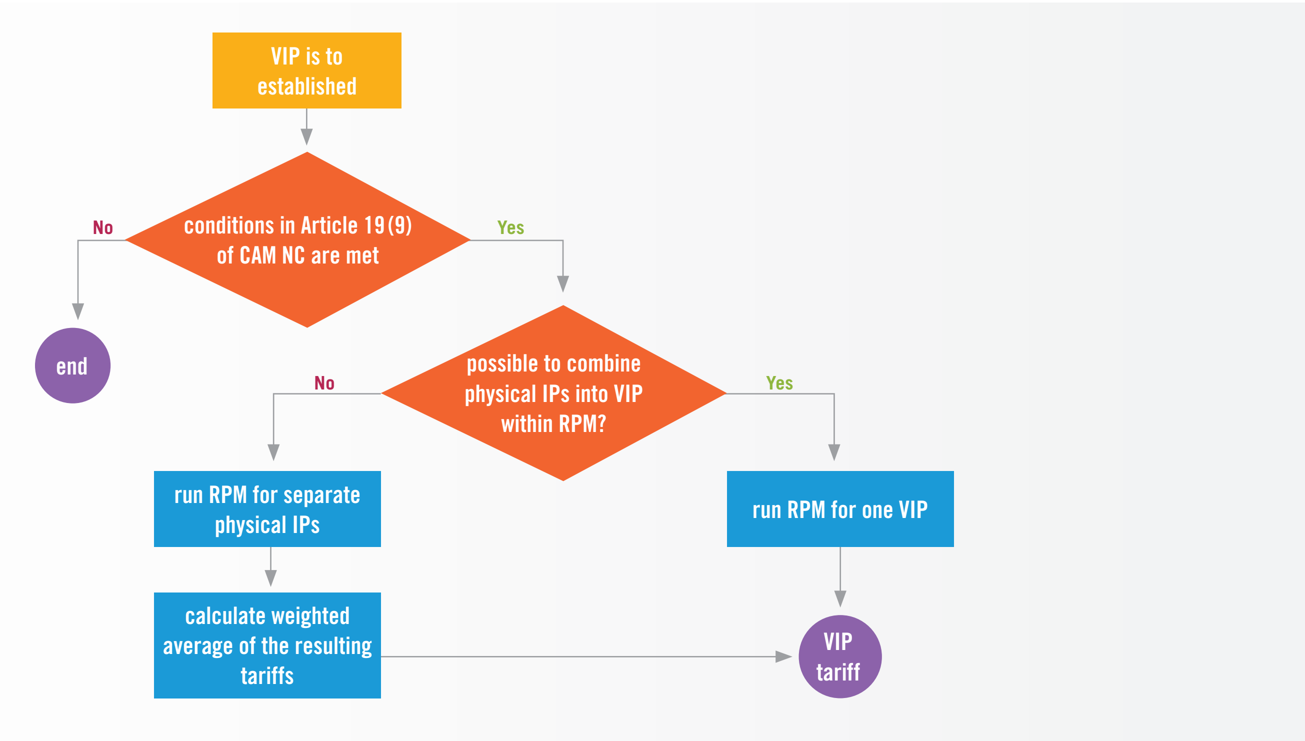


Figure 26: Calculation of the VIP tariff

Multiple TSOs at either or each side of the border

Figure 27 below illustrates the simplest example of multiple TSOs at either/each side of the border between the entry-exit systems: two TSOs at only one side of the border. The example assumes that these two TSOs are within the same entry-exit system, and that each applies the RPM separately[1].

In this example, the calculations by each TSO will not suffice for deriving one VIP tariff at the side of the border with two TSOs; an additional calculation is necessary. TSO C and TSO E must calculate an average of the respective values resulting from their fulfilment of the first step. It is suggested that this should be a weighted average, where the weights depend on the key cost driver such as forecasted contracted capacity.

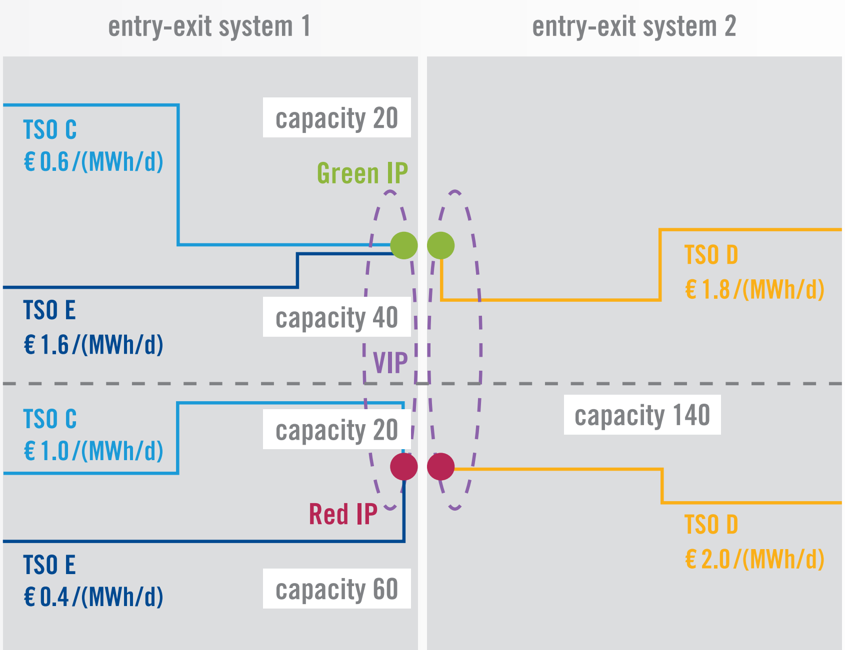


Figure 27: Illustration of the VIP with two TSOs at one side of the border

1) For details on approaches for applying RPM(s) in a multi-TSO entry-exit system within a MS, see Chapter II 'Reference price methodologies', Section 'Articles 10 and 11 – multi-TSO arrangements'.

Therefore, the calculation steps are:

1) As the first step, the tariff value at the border side 1 will be the result of the application of the individual RPM by TSO C and TSO E for all their products. Figure 27 shows a scenario as a starting point where both TSO C and E have still single tariffs for each IP. As introduced in the previous section each TSO therefore first derives its VIP tariff according to its capacities at each IP. TSO C would have a VIP tariff of 0.8 €/(MWh/d) for a capacity of 40 units which is the sum of capacity at a Green and Red IPs (20 units + 20 units), while TSO E would have a VIP tariff of 0.88 €/(MWh/d) for a capacity of 100 units which is the sum of capacity at a Green and Red IPs (40 units + 60 units).

2) The second step requires the calculation of a weighted average of the two tariffs resulting from the first step. In the figure above there is a forecasted contracted capacity 40 units on the VIP of TSO C, and 100 units on the VIP of TSO E. The weighted tariff on the side of entry-exit system 1 would then be as follows:

$$\mathbf{P} = \frac{40 \times 0.8\,€/(\mathrm{MWh/d}) + 100 \times 0.88\,€/(\mathrm{MWh/d})}{40 + 100} = \mathbf{0.86\,€/(MWh/d)}$$

3) After these two steps the VIP tariff at one side of the border is known for the unbundled capacity product. This VIP combines two IPs of two TSOs respectively. The price of the bundled capacity product is calculated as described in section 'Bundled capacity' above.

Chapter VI: Clearing and Payable Price

Chapter VI 'Clearing and Payable Price' of the TAR NC has the following structure: Article 23 sets out the 'clearing price' calculation; Articles 24 and 25 elaborate on 'payable price' calculation and conditions for offer a given payable price approach.

Image courtesy of National Grid

Summary

Scope: IPs
Application date: 1 October 2017

This Chapter first covers the calculation of the **clearing price:** the price when the capacity auction is closed, calculated as the reserve price plus any auction premium.

The second issue concerns the calculation of the payable price, for which two approaches are possible:

- **Floating payable price** based on the reserve price applicable at the time when a capacity product becomes usable; and
- **Fixed payable price** based on the reserve price published at the time of an auction, subject to indexation and a risk premium.

This Chapter also sets out the specific conditions for offering these approaches, depending on the applicable regulatory regime and on the nature of the capacity as existing or incremental.

The TAR NC sets out the formulas for all three calculations above: clearing price, floating payable price and fixed payable price.

Clearing Price

ARTICLE 23 WHAT A CLEARING PRICE IS

Responsibility: no implications for TSO/NRA responsibility

A clearing price is the price resulting from the auction. The two components that make up the clearing price are the reserve price and, if any, the auction premium. A clearing price may diverge from the payable price for the following reasons related to the reserve price used in the auction:

- Where the TSO does not have a tariff period that matches the gas year, the reserve price will only reflect the first part of the gas year depending on the applied tariff period. The reserve price will change part way through the gas year.
- For fixed tariffs beyond the gas year following the auction, the reserve price in later years is indexed.
- In a floating price regime, where capacity is bought for a gas year beyond the one following the auction, the reserve price is not known, as it will not be calculated until the auction prior to the gas year, unless the applied tariff period exceeds one year. Therefore, the clearing price will only reflect the indicative reserve price, and not the actual payable price.

Payable Price

PAYABLE PRICE: TWO APPROACHES

ARTICLE 24

Responsibility: fixed payable price approach for existing capacity under non-price cap regime is subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

The difference between the fixed and the floating payable price approaches is the degree of 'knowledge' with respect to the payable price when contracting the capacity:

- Under the floating payable price approach, where capacity is bought for a gas year beyond the next, the reserve price is not known. The reserve price will only be known before the annual yearly auction that takes place prior to the respective gas year. Therefore, the clearing price for future gas years will only reflect an indicative reserve price. The actual payable price will only be known upon the publication of the reserve price prior to the gas year. Any auction premium will not change.
- Under the fixed payable price approach, the basis and the evolution of the price is known prior to the annual yearly capacity auctions. That is, the reserve price is known, as is the type of index, even if the actual index value remains uncertain. Similarly, the risk premium is known.

FLOATING PAYABLE PRICE

ARTICLE 24(A)

Responsibility: no implications for TSO/NRA responsibility

General

The floating price approach is used to ensure that network users who buy capacity at a given point, pay the same as each other, regardless of when they procured the capacity. This aims to reduce cross subsidies between network users independent of when the network user buys the capacity.

The reference price for the yearly capacity product is calculated prior to the capacity auction immediately before the gas year. Network users will not know the reserve price for any yearly capacity product sold further ahead. The reference price of the capacity sold in following years will reflect the allowed/target revenues in the given year plus any reconciliation from previous years, if applicable.

Benefits for network users

Network users pay the same price for the capacity: Each network user, regardless of when they buy the yearly capacity, will pay the same price.

Reduces cross subsidies: The risk of a change in revenues is shared evenly between all network users, reducing the uneven distribution of revenues across the network users who buy the same capacity product and therefore, reducing the potential for cross subsidies.

Benefits for TSOs

Reflects revenue in a given year: The floating price reflects the revenues and assumptions for the capacity for the next gas year, providing a more cost reflective tariff.

Calculation of the floating payable price

Where the floating payable price approach is applied, the payable price for a given standard capacity product at an IP is calculated per formula below.

$$P_{flo} = P_{R,flo} + AP$$

Where:

P_{flo} is the floating payable price;

$P_{R,flo}$ is the reserve price for a standard capacity product applicable at the time when this product may be used, as set or approved by the national regulatory authority;

'AP' is the auction premium, if any.

In a floating price regime, the payable price is determined prior to the annual auction immediately before the gas year where the capacity may be used. The floating price is calculated using the RPM, with this price used as the **reserve price** in the auction. The payable price will then be determined by this reserve price and any auction premium.

The TAR NC defines the auction premium as the *'difference between the clearing price and the reserve price in an auction'*. Any auction premium is included in the floating payable price.

FIXED PAYABLE PRICE

ARTICLE 24(B)

Responsibility: fixed payable price approach for existing capacity under non-price cap regime is subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

General

The TAR NC has included a fixed payable price approach mainly as an incentive for network users to purchase long-term capacity. A fixed payable price approach improves price certainty, provides some certainty and stability for the TSO on future contracted capacity, and improves the signals for potential system development requirements.

Nevertheless, the fixed payable price approach may also have some drawbacks. A TSO can risk under-recovery if its costs change but its income does not, given the fixed payable price contracts. On the other hand, floating payable price contracts can risk cross-subsidisation. Also, improving the investment climate may not be relevant for TSOs that do not require significant investment in a declining market.

Benefits for network users

Price certainty from long-term capacity contracts: The fixed payable price approach improves network users' opportunity to manage their margin risk in conjunction with long-term supply contracts. Price certainty may prompt network users to commit to contract for capacity over a longer period.

Incremental aspect: A fixed payable price may be a more appropriate option for incremental capacity, where network users may need predictability before bidding for sufficient long-term capacities to justify a project economically, known as passing the economic test.

Benefits for TSOs

Income stability from long-term capacity contracts: As explained above, a fixed payable price approach encourages more long-term capacity bookings, and therefore provides increased certainty of TSO income, especially in a price cap regulatory regime.

Incremental aspect: Projected reserve prices affect the economic test for incremental capacity. A fixed payable price approach makes the economic test a more robust process, by facilitating projections of future reserve prices, which permits bidders to determine more accurately the present value of binding commitments. Under a floating payable price approach, the present value of binding commitments can only be a rough estimate, and estimation uncertainty increases with each subsequent year forecast. Estimation uncertainty may not present a significant issue in regulatory regimes that guarantee the revenues corresponding to an incremental project. However, in regimes with highly volatile estimated reserve prices, the fixed payable price approach helps to foster long-term commitments by network users, facilitating long-term investment.

Calculation of the fixed payable price

Where the fixed payable price approach is applied, the payable price for a given standard capacity product at an IP is calculated per formula below.

$$P_{fix} = (P_{R,y} \times IND) + RP + AP$$

Where:

P_{fix}	is the fixed payable price;
$P_{R,y}$	is the applicable reserve price for a yearly standard capacity product published at the time when the product is auctioned;
IND	is the ratio between the chosen index at the time of use and the same index at the time the product was auctioned;
RP	is the risk premium reflecting the benefits of certainty regarding the level of transmission tariff, where such premium shall be no less than 0;
AP	is the auction premium, if any.

The fixed payable price approach is for the yearly standard capacity product. The **reserve price** used in the formula is the one calculated for the annual yearly capacity auction.

As outlined below, the TAR NC allows fixed and floating payable price approaches to coexist. Co-existence at a given IP needs to be explained as part of the final consultation under Article 26(1), and approved by the NRA as part of the decision under Article 27(4). With different network users paying different prices for the same yearly capacity product, there will be inevitably some form of cross-subsidisation. The TAR NC mitigates cross-subsidisation to some extent by introducing indexation (IND) and risk premium (RP) concepts.

Indexation seeks to reflect the general evolution of prices over time. Different forms of indexation include financial inflation measures such as the producer price index, the retail price index and the cost of steel, and an index related to the calculation of the TSO's allowed revenue. Although elements of the fixed payable price will be known at the time of contract signature, the elements will 'update' using the relevant indexation during the period of contract performance. IND stands for the ratio between the chosen index at the time of the capacity product use, and the same index at the time of the capacity product auction. Depending on the chosen index, the fixed payable price could be higher or lower than the corresponding floating payable price.

The **risk premium** included in the formula should reflect the benefits of certainty regarding the level of transmission tariff for network users. The risk premium should simultaneously reflect the TSO's risk associated with fixing a certain price level over an extended period, which prevents adaptation as underlying costs change. The level of such risk premium must be no less than 0[1]. Generally, a longer time period justifies a higher risk premium, as the risk of adverse future changes is also higher.

The TAR NC defines the **auction premium** as the *'difference between the clearing price and the reserve price in an auction'*. Any auction premium is included in the fixed payable price.

1) The risk premium can be equal to zero in case the reserve prices exhibit low volatility and therefore, the application of indexation is the only change.

WHEN TO APPLY EACH PAYABLE PRICE APPROACH AND WHY

ARTICLE 25

Responsibility: fixed payable price approach for existing capacity under non-price cap regime is subject to consultation per Article 26(1) by TSO/NRA, as NRA decides; subject to decision by NRA

The TAR NC sets out the rules for offering different payable price approaches under different regulatory regimes, and for different types of capacity. Table 9 shows the distinction. Incremental capacity appears together with existing capacity, due to the definition of the 'offer level' in Article 3(5) of the CAM NC, which represents *'the sum of the available capacity and the respective level of incremental capacity'*. Also, it is noteworthy that the same TSO can function simultaneously under price cap and non-price cap regulatory regimes. In such case, the relevant rules apply to the respective part of the TSO's assets.[1)]

Conditions for offering fixed or floating payable price approaches may mitigate concerns about potential cross-subsidies between network users booking on a fixed price basis and those booking on floating price basis, which can arise from the reconciliation of under-recovery in a non-price cap regime. Under such a regime, only a floating payable price approach is allowed for existing capacity. A fixed payable price approach is allowed for incremental capacity where one of the following conditions is met:

- An alternative allocation mechanism set out in Article 30 of the CAM NC is used;
- A project is included in the Union list of projects of common interest as set out in Article 3 of Regulation (EU) No 347/2013[2)].

Under the price cap regime, the concerns about the potential cross-subsidies between network users resulting from reconciliation of under-recovery do not apply. Therefore, the floating payable price approach or the fixed payable price approach, or both, may be offered and no conditions are applied.

CONDITIONS FOR OFFERING PAYABLE PRICE APPROACHES

	Non-price cap regime	Price cap regime
Existing capacity	Only floating may be offered	Floating or fixed may be offered
Existing and incremental capacity	Floating or fixed* may be offered * Fixed can only be offered with conditions	

Table 9: Conditions for offering payable price approaches

1) See Chapter I 'General provisions', Section 'Article 3(3) and 3(17) – non-price cap and price cap regimes'.

2) Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009 (OJ L 115, 25.4.2013, p. 39).

Chapter VII: Consultation Requirements

Chapter VII 'Consultation Requirements' of the TAR NC has the following structure: Articles 26 and 27 address 'periodic consultation' that takes place at least every five years as from the first NRA decision; Article 28 deals with 'tariff period consultation' to take place every tariff period as from the first NRA decision. The IDoc Chapter finishes with a 'comparison' between the two consultations.

Summary

Scope: IPs and non-IPs (except for Article 28: IPs)
Application date: entry into force (6 April 2017)

This Chapter is a core Chapter of the TAR NC since the rules in almost all the other Chapters refer to it. It details the scope of two consultations:

1. For the **'periodic consultation'** done by the TSO/NRA at least every five years, the consultation scope includes:
   - The description of the proposed RPM and indicative reference prices as compared to the indicative reference prices calculated following the CWD counterfactual (Chapter II);
   - Storage, LNG and other discounts: at entry-points-from/exit-points-to-storage facilities, at entry-points-from LNG facilities and entry-points-from/exit-points-to infrastructure ending the isolation of gas transmission systems in certain MSs (Chapter II);
   - Some indicative information on the allowed/target revenue of a TSO (Chapter VIII);
   - Indicative information on commodity-based transmission tariffs and non-transmission tariffs (Chapter I);
   - Indicative information on tariff changes and trends (Chapter VIII);
   - Information on the fixed payable price approach under a price cap regime (Chapter VI).

As for the 'periodic consultation', there can be one or more consultations conducted on some/all enlisted components – however, there must also be a final consultation on all the components, on which the NRA bases a decision. The NRA approval process includes the analysis of the final consultation document by ACER. ACER must publish its analysis and send it to the TSO/NRA and the EC. A deadline of 31 May 2019 applies to the consultation and approval processes, and to the calculation and publication of tariffs in accordance with the NRA decision. 31 May 2019 does not match the beginning or end of any TSO's tariff period, so the 'new' tariffs will not apply from this date. The 'old' tariffs will apply until the end of each TSO's prevailing tariff period.

2. For **'every tariff period consultation'** undertaken by the NRA, the consultation scope includes:
   - Multipliers, seasonal factors and interruptible discounts (Chapter III);
   - Discounts at entry-points-from LNG facilities and entry-points-from/exit-points-to infrastructure ending the isolation of gas transmission systems in certain MSs (Chapter II).

Periodic Consultation

ARTICLE 26(1) CONTENT OF THE DOCUMENT FOR PERIODIC CONSULTATION AND COMPARISON TO CHAPTER VIII 'PUBLICATION REQUIREMENTS'

Responsibility: consultation by TSO/NRA, as NRA decides; decision by NRA

This section describes the content of the consultation document, while the following section details the consultation procedure.

The consultation document for the final consultation must include information listed in Table 10. The section below describes the difference between the 'final' and the 'intermediate' consultations.

Article 29 and Article 30 have a certain degree of overlap with respect to the publication requirements and the content of the final consultation document. Table 10 compares Article 26 to Articles 29 and 30 together. The information included in the final consultation document is only indicative, and is relevant for a given periodic consultation conducted at least every five years as from 31 May 2019 which is the deadline for the NRA decision on the first consultation. In contrast, the information for publication before the annual yearly capacity auctions, and before the tariff period, is binding and relevant for a given gas year or tariff period. Effectively, almost all the information included in the final consultation document subsequently 'converts' into binding information for publication before the annual yearly capacity auctions and before the tariff period. The latter information also includes other information not mentioned in Article 26. An example is the reserve prices, including multipliers, seasonal factors, interruptible discounts, which are subject to consultation every tariff period under Article 28, and not to periodic consultation under Article 26.


Image courtesy of Fluxys

CONTENT OF THE FINAL CONSULTATION DOCUMENT UNDER ARTICLE 26 (1)

Article 26 (1)	Content of consultation	Comparison with Articles 29 and 30
(a) Proposed RPM	Assumptions and justification for parameters used in the proposed RPM per Article 30(1)(a)	Article 30(1)(a): examples are provided, *'justification'* is not covered
	Proposed adjustments for points with storage, LNG facilities and infrastructure ending isolation of a MS per Article 9	Article 30(1)(c)(iii): part of the *'reference prices and other prices applicable at points other than where the CAM NC applies'*
	Indicative reference prices	Article 29: reserve prices at points where the CAM NC applies Article 30(1)(c)(iii): part of *'reference prices at points other than where the CAM NC applies'*
	Results, components and their details for CAA per Article 5	Article 30(1)(v)(3): partially covered by *'intra-system/cross-system split'*
	Assessment of the RPM	Not covered
	Comparison of RPM to the CWD in Article 8	Not covered
(b) Revenue and splits	Indicative allowed and / or target revenue	Article 30(1)(b)(i): allowed and/or target revenue
	Indicative transmission services revenue	Article 30(1)(b)(iv): transmission services revenue
	Indicative splits of capacity-commodity revenues, entry-exit revenues, intra-system/cross-system revenues	Article 30(1)(b)(v): splits of capacity-commodity revenues, entry-exit revenues, intra-system / cross-system revenues
(c) Commodity-based and non-transmission tariffs	Manner in which they are set	Article 30(1)(c): covered by *'relevant information related to their [tariffs] derivation'*
	Share of the allowed or target revenue to be recovered by these tariffs	Article 30(1)(b)(v)(1): covered by *'capacity-commodity split'* for commodity-based transmission tariffs Article 30(1)(b)(i) and (iv): covered by *'allowed and / or target revenue'* and *'transmission services revenue'* for non-transmission tariffs
	For non-transmission tariffs, manner of revenue reconciliation	Not covered
	Indicative tariffs	Article 30(1)(c)(i): commodity-based transmission tariffs Article 30(1)(c)(ii): non-transmission tariffs
(d) Changes in transmission tariffs	Changes in tariffs for comparable services from the prevailing tariff period to the tariff period for which information is published – indicative comparison between: (1) prevailing tariffs at the time when the consultation document is published; and (2) indicative tariffs based on the proposed RPM	Article 30(2)(a)(i)
	Changes in tariffs for comparable services from the tariff period for which information in published to each subsequent tariff period until the end of the prevailing regulatory period – indicative forecast based on the proposed RPM	Article 30(2)(a)(ii)
	At least a simplified tariff model to calculate tariffs and estimate a possible future evolution	Article 30(2)(b)
(e) Fixed payable price approach	Proposed index	Not covered
	Risk premium: calculation and proposed use	Not covered
	Where and when such approach is proposed	Not covered
	Process for offering capacity at IPs where both fixed and floating price approaches are offered	Not covered

Table 10: Content of the final consultation document under Article 26(1)

ARTICLE 26(2), 26(3) AND ARTICLE 27

PROCEDURE FOR THE PERIODIC CONSULTATION

Responsibility: consultation by TSO/NRA, as NRA decides; decision by NRA

Article 26(1) of the TAR NC stipulates *'one or more'* intermediate consultations and a *'final'* consultation. Such consultations are *'periodic'* as explained in the section below, and must be carried out either by the NRA or the TSO(s), as decided by the NRA.

ENTSOG has estimated the time needed for completing the final consultation process, and has also made assumptions regarding intermediate consultations. This section outlines the timeline for completing the final consultation, and the responsibilities of the various parties involved in the process.

'Final' consultation

The length of the final consultation process depends not only on the deadlines explicitly set out in the TAR NC but also on the time estimates of the related activities to be fulfilled before/after. The list below provides an overview of activities fixed and not fixed in the TAR NC with an indication of the respective timing, represented in Figure 28:

1. TSO/NRA to prepare the final consultation document – eight months (estimate).
2. TSO/NRA to conduct the final public consultation – at least two months as from point 1 above (fixed, Article 26(1)–(2)).
3. TSO/NRA to publish consultation responses and their summary – within one month as from point 2 above (fixed, Article 26(3)).
4. ACER to analyse certain aspects of the consultation document, publish the conclusion of its analysis and send it to the TSO/NRA and the EC – within two months as from point 2 above (fixed, Article 27(3)).
5. NRA to take and publish a motivated decision – within five months as from point 2 above (fixed, Article 27(4)).
6. TSO/NRA to update the calculation of tariffs and prepare the publication – within one month as from point 5 above (estimate). For multi-TSO entry-exit systems, more than one month may be needed due to e.g. the necessity of having the ITC mechanism.
7. NRA to approve and NRA/TSO to publish the final tariffs – within one month as from point 6 above (estimate).

The sum of the duration of all the points above is equal to at least 17 months where one TSO is active in an entry-exit system. As set out in Article 27(5) of the TAR NC, the deadline for NRA decision, calculation and publication of tariffs is 31 May 2019. Calculating 17 months backwards from 31 May 2019 brings us to the end of December 2017, the estimated date to start preparing the final consultation document, to comply with the TAR NC deadline. The process can also start after December 2017, the 'estimated' timings above would need to shorten accordingly. Figure 28 shows the start date. Multi-TSO entry-exit systems require additional time for step in point 6, so the relevant start date should shift earlier to around October 2017.

'Intermediate' consultations

17 months for the 'final' consultation leaves nine months to dedicate to 'intermediate' consultations on all/some elements listed in Article 26(1), extending from the entry into force of the TAR NC on 6 April 2017 to the estimated start date of December 2017 for preparing the final consultation document.

The TAR NC is flexible with respect to 'intermediate' consultations: there can be one consultation on all the elements of Article 26(1) or multiple consultations on specific elements of Article 26(1). The TAR NC is open about the number and format of the 'intermediate' consultations, which are only optional, but it mandates the duration and the format of the 'final' consultation. Such 'intermediate' consultations do not appear on the timeline below. Regardless of the content of 'intermediate' consultations, the final consultation must cover all the elements of Article 26(1) as Table 10 shows.

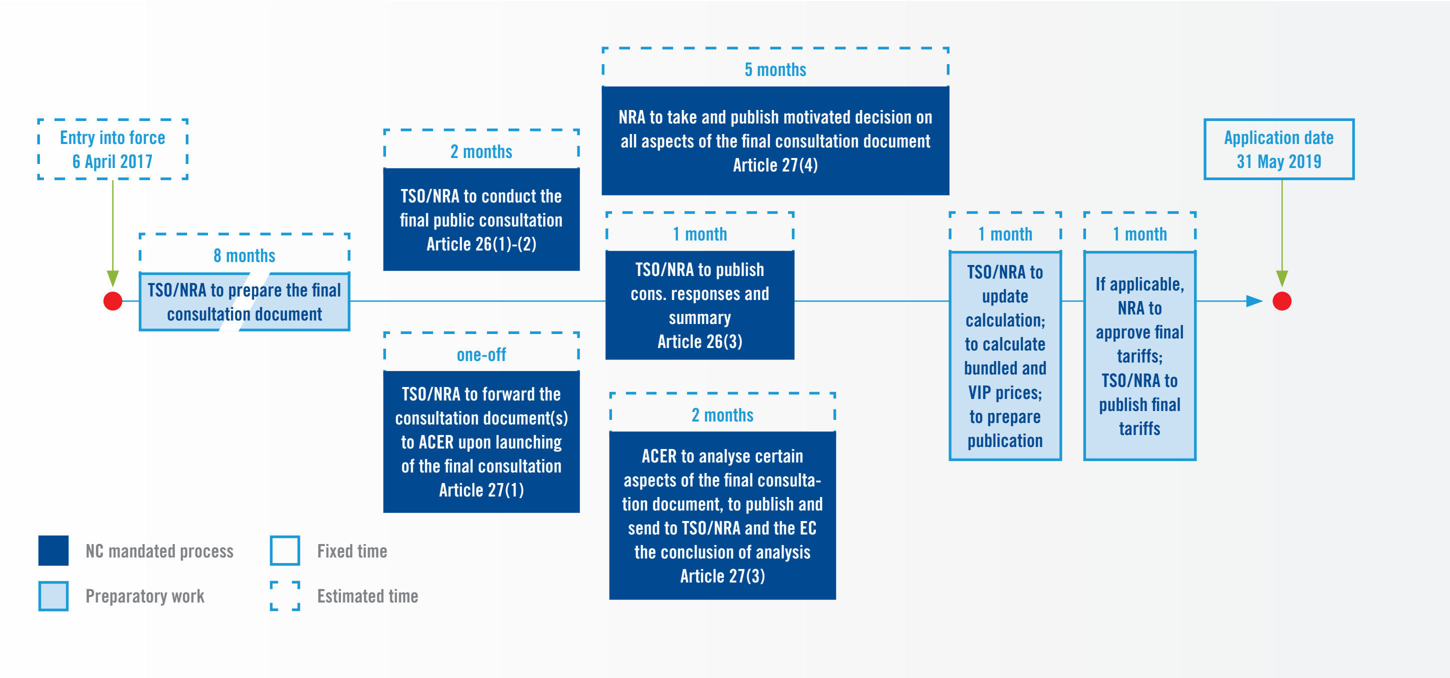


Figure 28: Final consultation timeline

ACER review

ACER review applies only to the 'final' consultation and not to the 'intermediate' consultations. As explained above, the 'final' consultation must cover all the elements of Article 26(1) even if they were subject to an 'intermediate' prior consultation. Under Article 27(2) of the TAR NC, ACER analysis follows:

- Checking for completeness: whether the final consultation document publishes all the information in Article 26(1);
- Checking for compliance with the TAR NC requirements: (i) the proposed commodity-based transmission tariffs must comply with Article 4(3); (ii) the proposed non-transmission tariffs must comply with Article 4(4); and (iii) the proposed RPM must comply with Article 7.

Other information

The TAR NC foresees a number of measures to improve the transparency of the consultation process for both 'intermediate' and 'final' consultations:

- The consultation documents and the summary of the consultation responses should be provided in English to the extent possible;
- A possible requirement for any confidential consultation response to attach a non-confidential version suitable for publication;
- ACER must develop a template for the consultation document and, after consultation with ENTSOG, make it available by 5 July 2017.

ARTICLE 27(5) 'NEW' TARIFFS

Responsibility: subject to national decision regarding the tariff period

31 May 2019 ('AD 3') is the date for applying Chapter II 'Reference price methodologies', Chapter III 'Reserve prices' and Chapter IV 'Reconciliation of revenue'. The date falls within the gas year October 2018–September 2019, for which the binding reserve prices will be published in June 2018.

The TAR NC stipulates that 31 May 2019 does not imply a change in the reserve prices. Article 27(5) clarifies that the tariffs applicable for the prevailing tariff period as of 31 May 2019 remain 'until the end' of the period.

Table 11 provides an overview of the remaining time period for 'old' tariffs. Figure 29 shows with red crosses the tariff period from which 'new' tariffs apply, for four cases where the tariff period is equal to one year.[1)]

BORDER DATE BETWEEN 'OLD' AND 'NEW' TARIFFS

Concerned MS	Tariff period prevailing as of 31 May 2019	'Old' tariffs applicable until	'New' tariffs applicable as from	Sequence of change to 'new' tariffs
BG, CZ, DE, ES, FI, GR, HR, IT, LT, LU, NL, PL, SI, SK	1 January 2019 – 31 December 2019	31 December 2019	1 January 2020	3rd to change
FR	1 April 2019 – 31 March 2020	31 March 2020	1 April 2020	4th to change
PT	1 July 2018 – 30 June 2019	30 June 2019	1 July 2019	1st to change
DK, GB, HU[1)], IE, NIR, RO, SE	1 October 2018 – 30 September 2019	30 September 2019	1 October 2019	2nd to change
AT	1 January 2017 – 31 December 2020	31 December 2020	1 January 2021	5th to change
BE	1 January 2016 – 31 December 2019	31 December 2019	1 January 2020	3rd to change

Table 11: Border date between 'old' and 'new' tariffs

Although Table 11 shows that Portugal is the 1st MS to switch from 'old' tariffs to the 'new' ones, this only applies to non-IPs. The tariffs at IPs applicable at 31 May 2019 will persist for an additional three months beyond the end of the prevailing tariff period on 30 June 2019, to 30 September 2019. ENTSOG has estimated that 17 months are needed for all the process to calculate the 'new' tariffs[2)]. Therefore, in case the deadline of 1 July 2019 applies for a switch to the 'new' tariffs for all points, it would be necessary to start preparing the final consultation document already in December 2016 when the TAR NC was still under the scrutiny of the European Parliament and the Council. Hence, Figure 29 shows 'new' tariffs twice for the tariff period July–June: for non-IPs, the 'new' tariffs apply as of July 2019, while for IPs, the 'new' tariffs apply as of October 2019. Such an approach has implications for separate reserve prices, reflected in Chapter III 'Reserve prices', and also has implications for the publication requirements reflected in Annex O.

1) The current tariff period applicable in Hungary is January–December. It will be changed to October–September as from 2017.

2) See Section 'Article 26(2), 26(3) and Article 27 – procedure for the periodic consultation'.

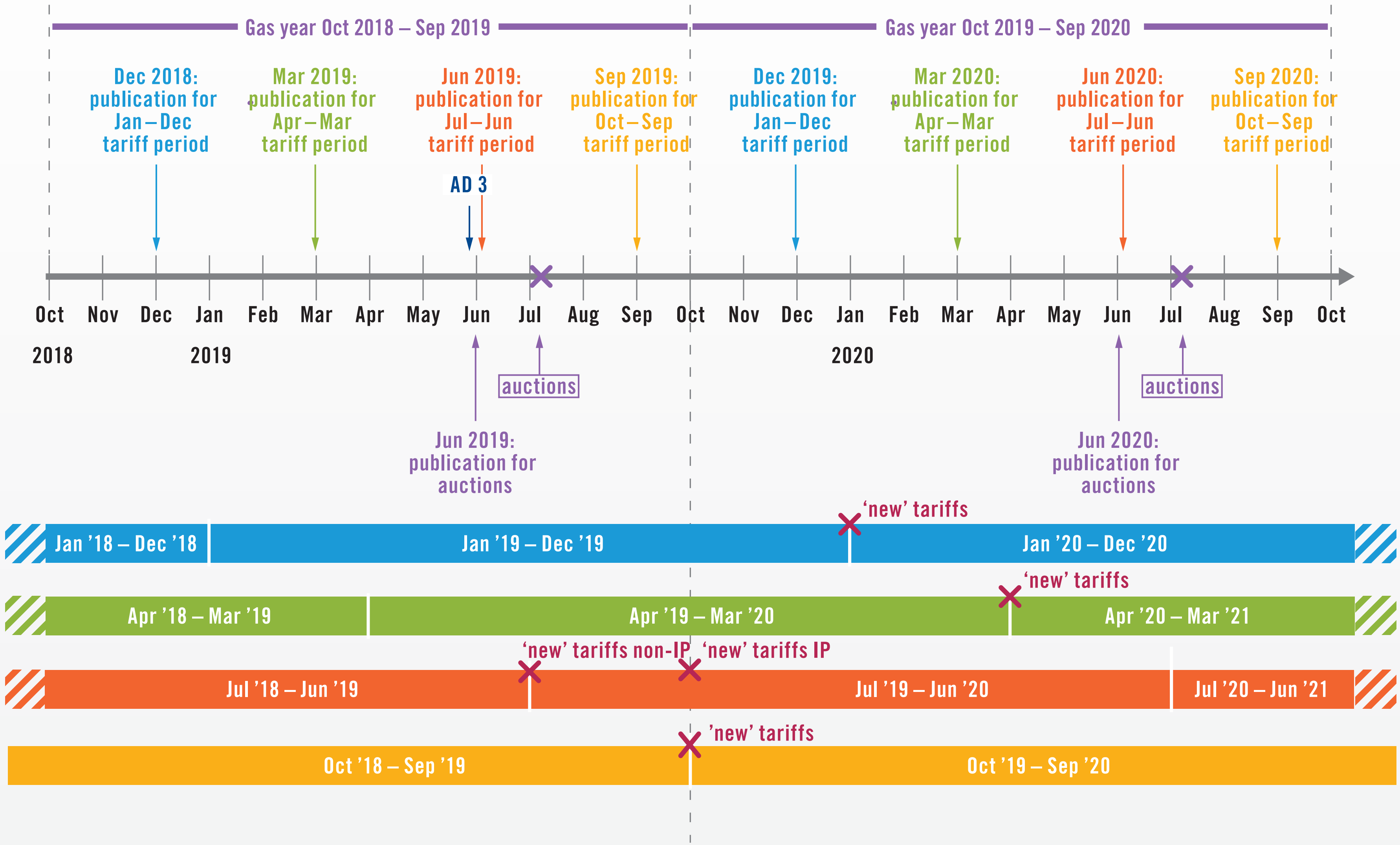


Figure 29: AD 3 and 'new' tariffs

ARTICLE 28(1) CONTENT OF THE DOCUMENT FOR CONSULTATION ON MULTIPLIERS, SEASONAL FACTORS AND DISCOUNTS

Responsibility: consultation by NRA; decision by NRA

This section describes the content of the consultation document, while the following section details the consultation procedure.

The consultation document must include the information outlined in Table 12.

CONTENT OF THE CONSULTATION DOCUMENT PER ARTICLE 28(1)

Article 28(1), content of consultation	Remarks
(a) Multiplier level per Article 14	Obligatory Needs to be consulted even if the multiplier level does not change from the previous NRA decision
(b) Seasonal factors per Article 15	Optional Depending on whether seasonal factors are applied or not Both the level of seasonal factors and the calculations for seasonal factor methodology must be consulted upon
(c) Discounts for entry points from LNG and entry-points-from / exit-points-to 'isolation' infrastructure per Article 9(2)	Optional Depending on whether such discounts are proposed for the points concerned Overlap with consultation per Article 26(1)
(c) Discounts for interruptible products	Obligatory Ex-ante and ex-post discounts level must be consulted upon

Table 12: Content of the consultation document per Article 28(1)

The scope of the consultation is limited to IPs by default, including their multipliers, seasonal factors and interruptible discounts, and for discounts for entry-points-from LNG facilities and entry-points-from/exit-points-to infrastructure ending the isolation of MSs. If a decision is taken to extend the scope of Chapter III 'Reserve prices' to non-IPs, then the consultation must also cover such non-IPs.

PROCEDURE FOR THE CONSULTATION ON MULTIPLIERS, SEASONAL FACTORS AND DISCOUNTS

ARTICLE 28(1) AND (3)

Responsibility: consultation by NRA; decision by NRA

General

At the same time as the final consultation under Article 26(1), the NRA must consult with the NRAs of directly connected MSs, and with relevant stakeholders on the aspects outlined in Table 10. The mention of NRAs from directly connected MSs is important to ensure NRA cooperation regarding the level of multipliers, seasonal factors and discounts applicable at either side of an IP.

The TAR NC calls for two consultations to occur at the same time, with the same start and duration. Also, the TAR NC requires the publication of responses for the consultation under Article 26 within the defined time frame. The TAR NC sets a deadline of 31 May 2019 for NRAs to select the applied RPM, to calculate and publish the resulting tariffs. However, the TAR NC is silent as to the time for the NRA to publish the consultation responses under Article 28 and the associated NRA decision-making by 31 May 2019. ENTSOG assumes that the overall timeline of the two consultation processes should be aligned as outlined in Part 2 'Indicative timeline for the TAR NC implementation', Chapter II 'General timeline': (1) the consultations are estimated to start at the end of August 2018 and finish at the end of October 2018; (2) the consultation responses should be published at the end of November 2018; and (3) the final NRA decisions on two consultations are to be taken simultaneously by 31 May 2019. As explained in Part II, the deadline of 31 May 2019 includes not only NRA decision-making on the Article 26 consultation, but also calculation and publication of tariffs in accordance with the approved RPM.

ENTSOG believes that the first iteration of consultation under Article 26(1) and Article 28(1) may be merged into one consultation where the NRA is responsible for consulting. Such merging may also be possible for subsequent consultations where the Article 26(1) consultation cycle coincides with the Article 28(1) consultation cycle as indicated below in Figure 30.

The next section compares the two consultations.

Criteria for NRA consideration

When adopting their decisions, the NRAs must consider the consultation responses received and the following factors:

1. **For multipliers:**
   - The balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system;
   - The impact on the transmission services revenue and its recovery;
   - The need to avoid cross-subsidisation between network users and to enhance the cost-reflectivity of reserve prices;
   - Physical and contractual congestion;
   - Effects on cross-border flows.
2. **For seasonal factors:**
   - Facilitating the economic and efficient utilisation of the infrastructure;
   - The need to improve the cost-reflectivity of reserve prices.

Such aspects have been selected as relevant ones based on discussions with stakeholders within the TAR NC establishment process.

ARTICLE 27(5) AND 28(2)

REPETITIVE CONSULTATION PROCESSES AND COMPARISON

Responsibility: consultation per Article 26(1) is by TSO/NRA, as NRA decides, and decision is by NRA; consultation per Article 28(1) is by NRA, and decision is by NRA

Table 13 compares procedural aspects of the consultations under Article 26(1) and Article 28(1).

COMPARISON OF CONSULTATIONS UNDER ARTICLES 26(1) AND 28(1)		
Aspect	**Consultation per Article 26(1)**	**Consultation per Article 28(1)**
Content of the consultation	See Table 10 Overlap for discounts (LNG, 'isolation')	See Table 11 Overlap for discounts (LNG, 'isolation')
Who is consulting	TSO or NRA, as decided by NRA	NRA
Who is consulted	Stakeholders	'NRAs from all directly connected MSs and relevant stakeholders'
Start of the first procedure	May be initiated as from the TAR NC entry into force	
End of the first procedure	As from 31 May 2019[1)]	
Start of the subsequent procedures	At least every five years as from the NRA decision per first procedure	Every tariff period as from the NRA decision per first procedure
End of the subsequent procedures	By 31 May 2024 and every five years thereafter	Minimum 30 days before publishing information for the annual yearly capacity auctions

Table 13: Comparison of consultations under Articles 26(1) and 28(1)

As Table 13 shows, the procedure per Article 26(1) must repeat at least every five years as from 31 May 2019, while the Article 28(1) procedure must recur every tariff period, and 30 days before the annual yearly capacity auctions. 'Subsequent consultations' must occur even if no changes are foreseen from previous NRA decisions. The two consultation processes therefore coincide at least every five years. Figure 30 shows the example of a one-year January–December tariff period where the Article 26(1) consultation repeats exactly every five years. The example does not reflect the idea of 'merging' the consultations as described above.

1) See Section 'Article 27(5) – 'new tariffs' for implications for the prevailing tariffs at the date of 31 May 2019.

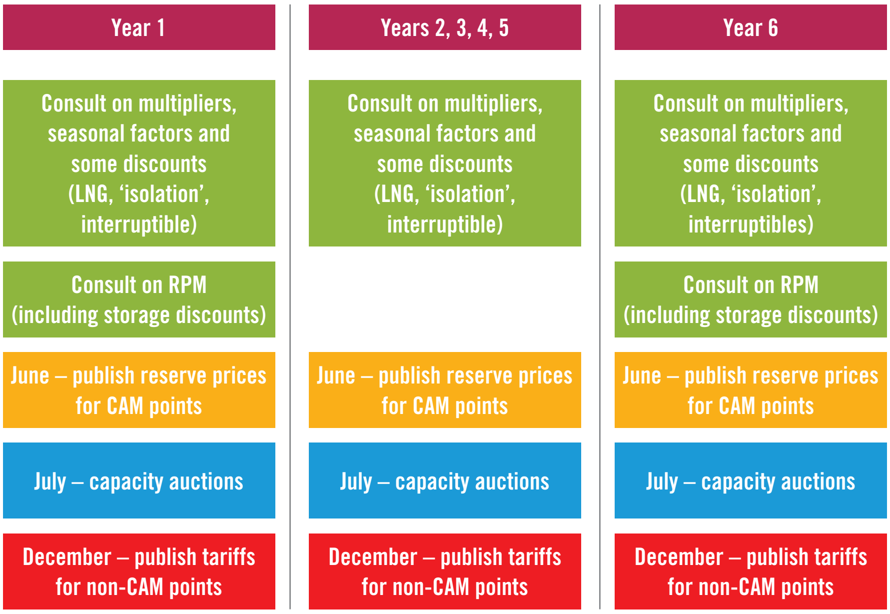


Figure 30: Timing interrelation between consultation per Article 26(1) and per Article 28(1)[1)]

1) Topics for Year 1 and Year 6 are covered by Article 26 and Article 28 consultations. Topics for Years 2, 3, 4, and 5 are covered by Article 28 consultation only.'

Chapter VIII: Publication Requirements

Chapter VIII 'Publication Requirements' of the TAR NC has the following structure: Articles 29 and 30 explain 'what' information to publish; Article 31 elaborates on 'how'; Article 32 sets out 'when' to publish such information.

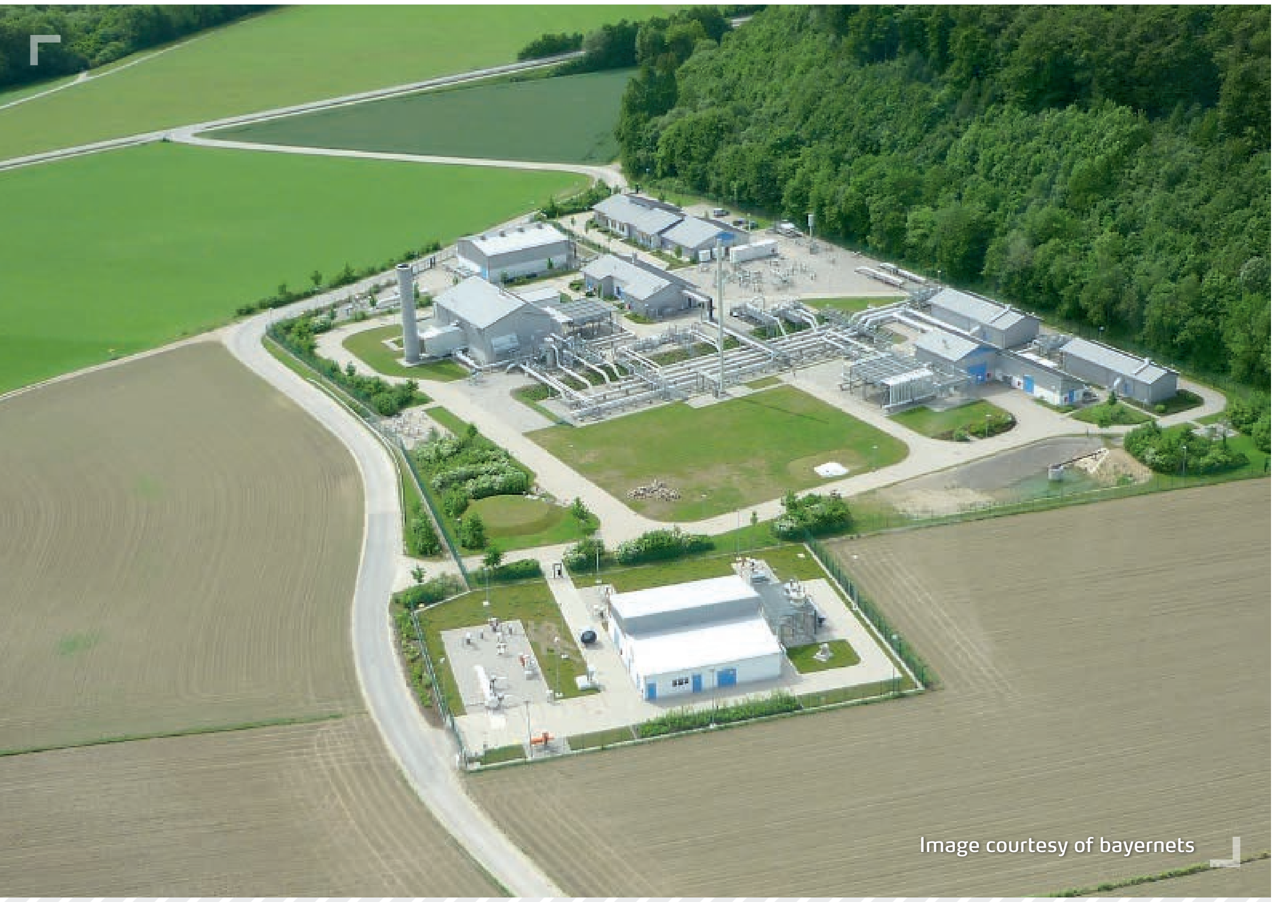


Image courtesy of bayernets

Summary

Scope: IPs and non-IPs
Application date: 1 October 2017

This Chapter lists tariff publication requirements, their manner and timing: what, how and when. The **entity** responsible for publication is either the TSO or the NRA, as decided by the NRA.

The **'what'** covers two sets of information:

- Information to be published before the annual yearly capacity auctions; and
- Information to be published before the tariff period.

The first set of information includes binding reserve prices for firm and interruptible capacity at IPs, with information concerning their calculation. The second set of information is more detailed, and includes the following:

- Technical parameters used in the RPM;
- Information on the allowed/target revenue of a TSO;
- Transmission and non-transmission tariffs not published within the first set of information;
- Information on tariff changes and trends;
- At least a simplified model enabling an estimation of possible tariff evolution.

As for the **'when'**, the deadlines are the same for publication on the TSO/NRA websites and on the ENTSOG's TP: at least 30 days before the annual yearly capacity auction/tariff period. Although the Chapter first applies on 1 October 2017, compliance with its requirements will take place later depending on the date of the auctions and on the start date of the tariff period for a specific TSO.

As for the **'how'**, both sets of information are to be published on TSO/NRA websites, and ENTSOG's TP must also provide a link to the websites. In addition, certain information needs to be duplicated directly on the ENTSOG's TP, in a standardised table and only for IPs, including:

- Firm and interruptible reserve prices;
- Flow-based charge, if any; and
- A simulation of all the costs for flowing 1 GWh/day/year at a given IP.

What to publish

The TAR NC outlines two sets of tariff-related information for publication: (1) the set of information before the annual yearly capacity auctions; and (2) the set of information before the tariff period. Splitting this information into two sets ensures clarity concerning the publication of particular information at different times of the year. As explained below, the 'dual' publication reflects the mismatch between the timing of the auctions and different start dates for tariff periods throughout the EU.

ARTICLE 29 INFORMATION FOR PUBLICATION BEFORE THE ANNUAL YEARLY CAPACITY AUCTIONS

Responsibility: publication by TSO/NRA, as NRA decides

Figure 31 below summarises the set of information for publication before the annual yearly capacity auctions. To ensure sufficient clarity regarding the derivation of binding reserve prices published before the auctions, this set also includes information on: (1) applied multipliers and justification for their level; (2) applied seasonal factors and justification for their application; and (3) an assessment of the probability of interruption.

Therefore, although such publication of reserve prices and the associated information occurs before the annual yearly capacity auctions, it covers all standard capacity products. This set represents the full explanation of the rationale behind the published binding reserve prices. Such information needs to be published both at IPs and non-IPs where the CAM NC applies.

For the first time when the information before the annual yearly capacity auctions is published in June 2018, it may not be the full set of information as Chapter III 'Reserve prices' applies as from 31 May 2019.

For an example on how to structure the assessment of the probability of interruption, please see Annex O.

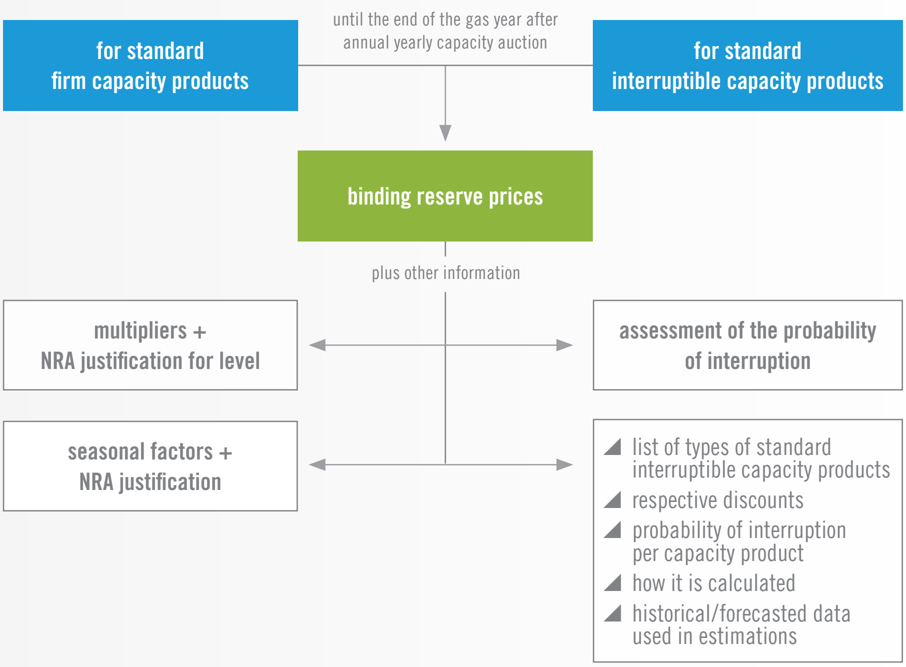


Figure 31: Information for publication before the annual yearly capacity auction

INFORMATION FOR PUBLICATION BEFORE THE TARIFF PERIOD

ARTICLE 30

Responsibility: publication by TSO/NRA, as NRA decides

Set of information for publication

Four blocks illustrate the set of information to publish before the tariff period: (1) methodology parameters related to technical characteristics of the transmission system; (2) TSO revenue information; (3) transmission and non-transmission tariffs, which are not published before the annual yearly capacity auctions; and (4) additional information related to tariff evolution. (See figure 33 on the following page)

Tariff changes, trends and tariff model

Figure 33 shows 'other' information that needs to be published before the tariff period, comprising information on tariff changes, tariff trends and at least a simplified tariff model. Such information only concerns transmission tariffs.

Annex P provides a description of the simplified tariff model. As for the information on tariff changes/trends, the TAR NC provides stakeholders with the opportunity to understand:

- The derivation of tariffs – an explanation of the reasons why tariffs changed as compared to the past (tariff changes);
- The future evolution of tariffs – an explanation of the reasons why tariffs may change in future, based on the best estimates (tariff trends).

Figure 32 shows an example of information to be published on tariff changes/trends for a given standard capacity product. The regulatory period is four years, and the prevailing tariff period is year 1 of 4, while the information is published for the tariff period which is year 2 of 4. Therefore, the reserve price for year 2/4 is binding while the reserve prices for years 3/4 and 4/4 are predictions.

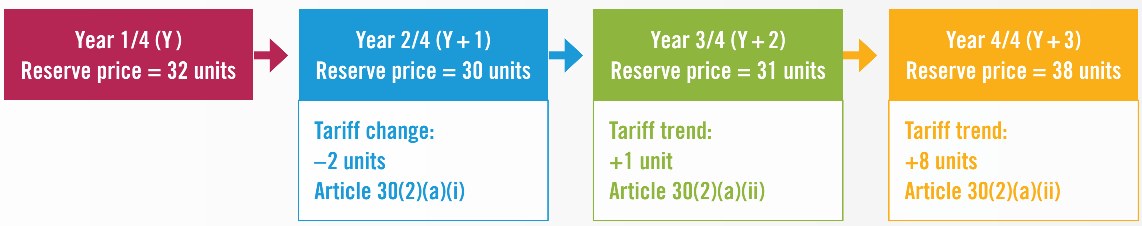


Figure 32: Example 1 of publication of tariff changes and trends

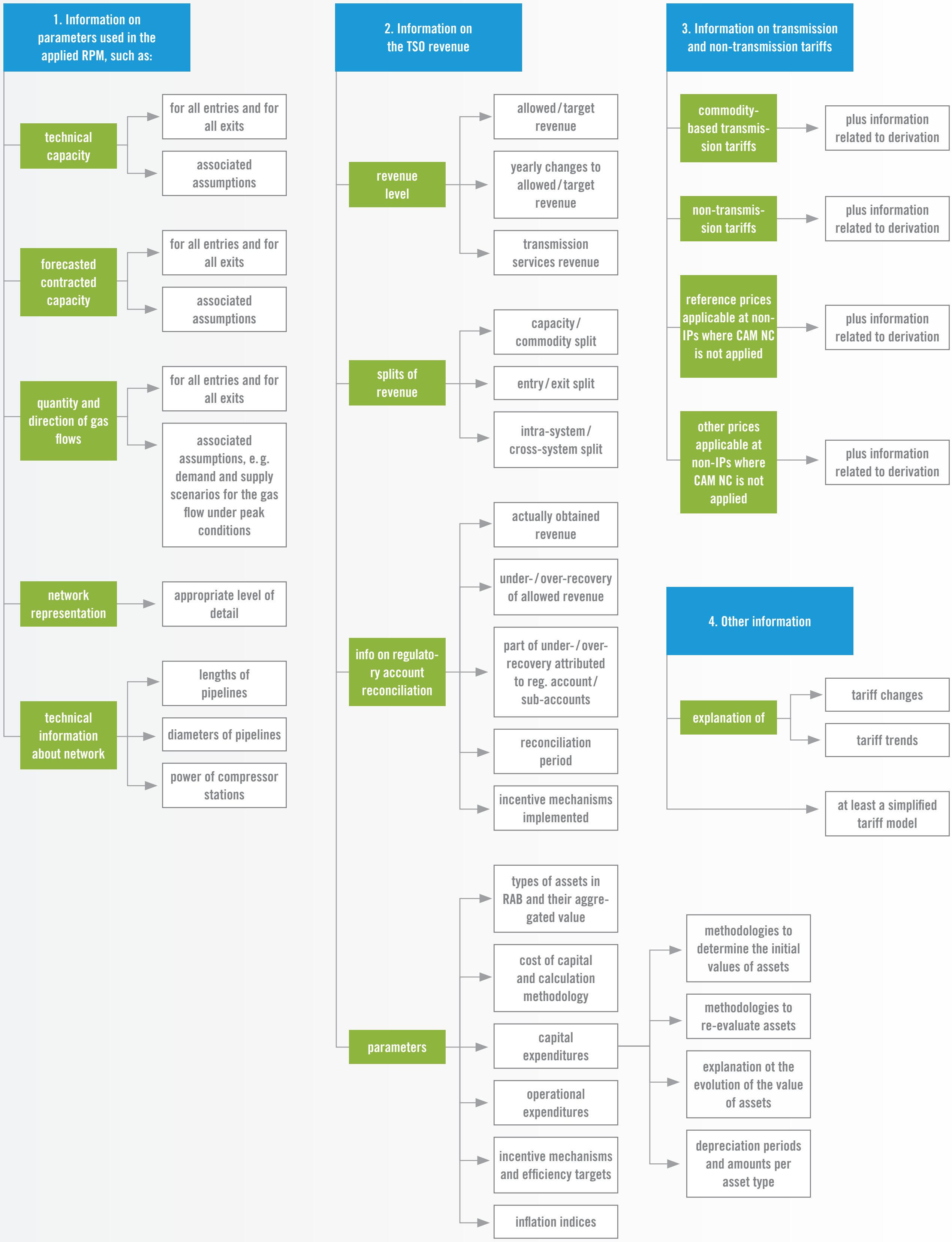


Figure 33: Information for publication before the tariff period

Table 14 shows another example of publication of tariff changes and trends for a yearly standard capacity product. Although the Table indicates tariffs, it may also be possible to publish *'the difference'* in the tariffs as set out by the TAR NC using other approaches, such as expected ranges for tariffs, percentage changes or expected ranges for percentage changes.

EXAMPLE 2 OF PUBLICATION OF TARIFF CHANGES AND TRENDS

Tariff period	Year in regulatory period	Entry points				Exit points			
		Entry 1	Entry 2	Entry 3	Entry 4 (new)	Exit 1	Exit 2	Exit 3	Exit 4 (new)
Prevailing tariff period (Y=0)	2019	10.05	32.32	32.32	–	38.05	58.82	42.82	–
Tariff period for publication (Y+1)	2020	20.03	29.74	28.50	–	36.02	56.73	42.30	–
Change from (Y=0) to (Y+1)	**2020 vs. 2019**	**9.98**	**−2.58**	**−3.82**	**–**	**−2.03**	**−2.09**	**−0.52**	**–**
Forecast for the subsequent tariff period (Y+2)	2021	30.20	30.20	30.20	–	37.50	60.00	45.00	–
Trend from (Y+1) to (Y+2)	**2021 vs. 2020**	**10.17**	**0.46**	**1.70**	**–**	**1.48**	**3.27**	**2.70**	**–**
Forecast for the subsequent tariff period (Y+3)	2022	38.00	38.00	38.00	38.00	40.00	67.00	50.00	50.00
Trend from (Y+1) to (Y+3)	**2022 vs. 2020**	**17.97**	**8.26**	**9.50**	**n/a**	**3.98**	**10.27**	**7.7**	**n/a**

Table 14: Example 2 of publication of tariff changes and trends

The information on tariff trends will be provided to the stakeholders as tentative. However, explanations must be sufficient to enable third parties to make reasonable estimates of the tariffs up until the end of the current regulatory period. If any input parameters might significantly affect future tariffs, their potential impact should be disclosed.

Reference to the Transparency Guidelines

Point 3.2(1)(a) of the Transparency Guidelines exempts certain points from some of the TAR NC transparency requirements: those exit points connected to a single final customer, and entry points linked directly to a production facility of a single producer located within the EU. Grounds of confidentiality and commercial sensitivity exempt two information items at those points: forecasted contracted capacity and forecasted flows. Publication of the two information items can still occur in aggregated format, at least per balancing zone as specified in point 3.2(2) of the Transparency Guidelines, which matches the level of granularity for publishing other information at such points under the Transparency Guidelines.

How to Publish

ARTICLE 31 FORM OF PUBLICATION

Responsibility: publication by TSO/NRA, as NRA decides

The TAR NC sets out the requirements for publishing information on TSO/NRA websites and on ENTSOG's TP. Table 15 outlines similarities and differences for the publication of tariff information on these websites, in particular in the columns 'how', 'for which points' and 'language'.

FORM OF PUBLICATION OF INFORMATION ON TSO/NRA WEBSITE AND ENTSOG'S TP

Where	Similarities		Differences			
	When	When	What	For which points	Language	Additional
On the website of TSO/NRA	◢ Before auctions ◢ Before the tariff period	◢ In a user-friendly manner ◢ Clear, easily accessible way ◢ On a non-discriminatory basis ◢ Downloadable format	All tariff information	All points on the system	In official language(s) of MS + in English, to the extent possible	Plus a link on ENTSOG's TP
Directly on ENTSOG's TP			Some tariff information: ◢ Reserve prices ◢ Flow-based charge ◢ Simulation of all costs for flowing 1 GWh/day/year	IPs only	In English only	In a standardised table

Table 15: Form of publication of information on TSO/NRA website and ENTSOG's TP

ARTICLE 31(1) TEMPLATE ON TSO/NRA WEBSITE

Responsibility: publication by TSO/NRA, as NRA decides

Similar to a template for publishing information under the Transparency Guidelines, ENTSOG suggests publishing two sets of information, before the annual yearly capacity auctions and before the tariff period, in such a way as to facilitate identifying the publication requirements and the respective cross-reference to Article, its paragraph and point as set out in the TAR NC. It is suggested that such templates should include a column with the reference to the appropriate provision of the TAR NC, a column with the quote from such provision, and a column with the respective tariff information. As for the third column, the information can be placed either directly in the cell of the template or contain a link to another webpage.

STANDARDISED TABLE ON ENTSOG'S TRANSPARENCY PLATFORM

ARTICLE 31(3)(C)

Responsibility: TSO/NRA sends information to ENTSOG's TP, as NRA decides

The TAR NC requires the publication of information directly on ENTSOG's TP in a standardised table. As outlined in Annex Q, publication will occur twice per calendar year for each case where the tariff period is equal to one year, except for the tariff period July–June, since in this case the publication of information before the tariff period and before the annual yearly capacity auction will occur simultaneously. As Table 15 shows, the standardised table must report the following information: reserve prices for standard capacity products, flow-based charges and a simulation of all the costs for flowing 1 GWh/day/year for each IP.

The TAR NC lists the minimum requirements for designing the standardised table. In general, the standardised table must include: the IP name, the gas flow direction and the relevant TSOs' names. For reserve prices, the additional information includes: whether the relevant product is firm or interruptible, whether its duration is yearly, quarterly, monthly, daily or within-day, the applicable tariff per kWh/h and per kWh/d in both local currency and the euro. The table must also indicate flow-based charges and simulation of all the costs for flowing 1 GWh/day/year for each IP in local currency and the euro.

The TAR NC contains appropriate caveats due to different capacity units and different currencies applied in the EU. The following information included in the standardised table is non-binding: (1) the applicable tariff per kWh/d (or per kWh/h) if the applied capacity unit is kWh/h (or kWh/d); and (2) the applicable tariff in euro and the simulation of all the costs in Euro if the local currency is other than the Euro.

When to Publish

ARTICLE 31 PUBLICATION NOTICE PERIOD

Responsibility: publication by TSO/NRA, as NRA decides

The figure below captures the two gas years as from October 2017, and illustrates the deadlines for publishing information: (1) before the annual yearly capacity auction; and (2) before the tariff period. For both sets of information, the publication notice period is the same – minimum 30 days.

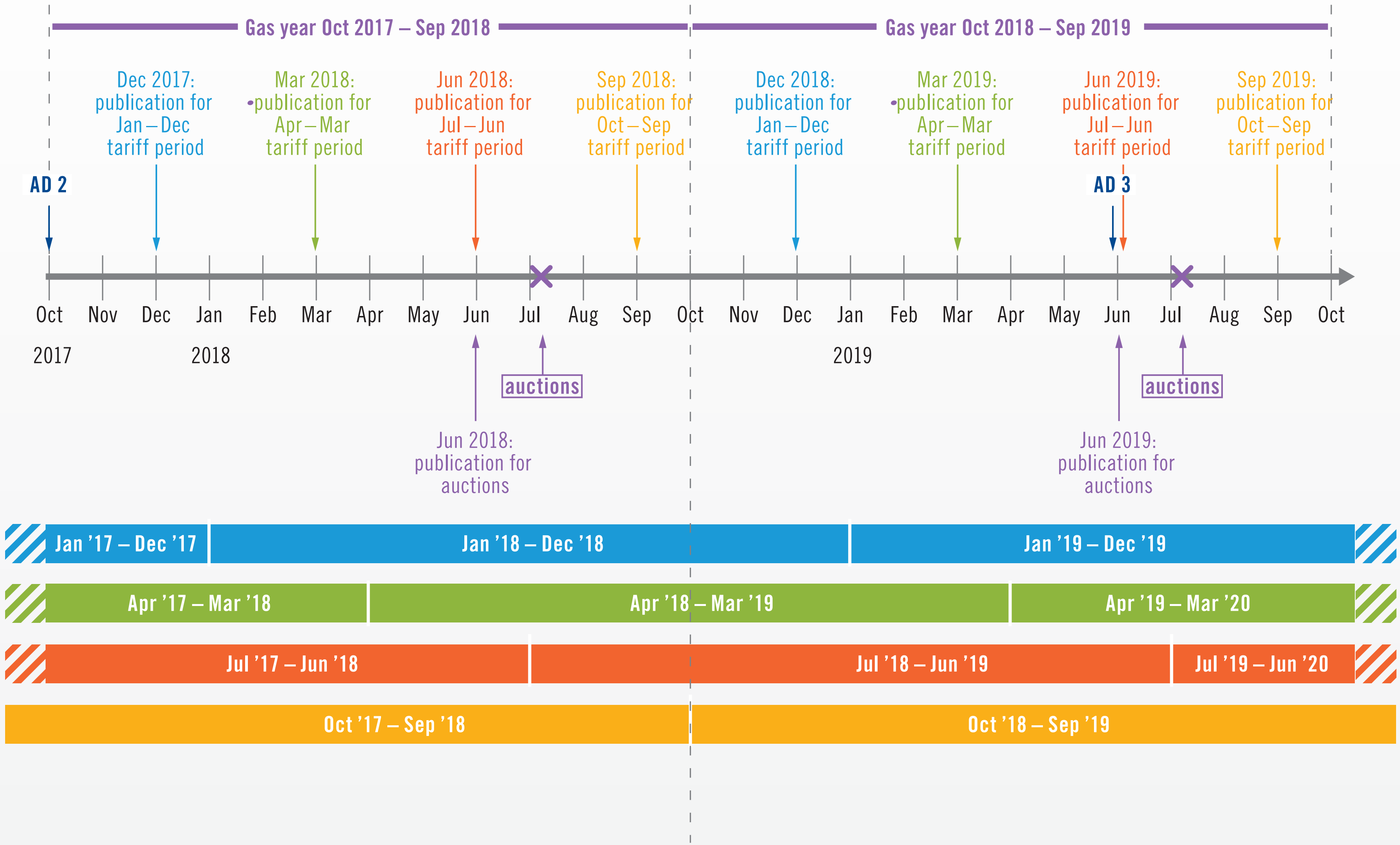
Chapter VIII 'Publication requirements' first applies on October 2017 (AD 2). However, the compliance date with the obligations foreseen in this Chapter occurs later, depending on the start date of the tariff period and the date of the annual yearly capacity auctions.

For information to be published before the annual yearly capacity auctions, in all MSs the deadline is June 2018 for auctions in July 2018, and June 2019 for auctions in July 2019. For information to be published before the tariff period, the deadlines are:

- December 2017 and December 2018 for publishing information before the tariff period January 2018–December 2018 and January 2019–December 2019, respectively;
- March 2018 and March 2019 for publishing information before the tariff period April 2018–March 2019 and April 2019–March 2020, respectively;
- June 2018 and June 2019 for publishing information before the tariff period July 2018–June 2019 and July 2019–June 2020, respectively;
- June 2018 and June 2019 for publishing information before the auctions in July 2018 and July 2019, respectively;
- September 2018 and September 2019 for publishing information before the tariff period October 2018–September 2019 and October 2019–September 2020, respectively.

Figure 34 covers only the four cases where the tariff period is equal to one year, and does not cover the tariff periods of greater than one year in Austria and Belgium.

Figure 34: Publication notice period timeline



Chapter IX: Incremental Capacity

Chapter IX 'Incremental Capacity' of the TAR NC has only one Article dealing with 'tariff principles'. Still, the IDoc Chapter starts with an 'overview of incremental process foreseen by the Amended CAM NC'.

Image courtesy of FluxSwiss

Summary

Scope: IPs
Application date: 6 April 2017

This Chapter has one Article dealing with the **tariff principles for incremental capacity.** The Amended CAM NC sets out the rest of the incremental rules.

Overview of Incremental Process

INCREMENTAL PROCESS IN THE AMENDED CAM NC

Responsibility: TSO/NRA responsibility: TSOs submit the project proposal to NRAs; NRAs take and publish coordinated decisions on the project proposal

The incremental process introduced by the Amended CAM NC is a standardised procedure for market participants to indicate in a non-binding way their demand, to allocate incremental capacity. 'Incremental capacity' covers a capacity increase at an existing IP, the installation of a physical reverse flow at an IP that has not been offered before, or capacity at a new IP.

The incremental process is a standardised process ensuring a general level of cross-border coordination between TSOs and NRAs, which serves to establish the economic viability of an incremental capacity project. Incremental and existing capacity must be offered jointly in the annual yearly capacity auction by default or, under certain conditions, pursuant to an alternative allocation mechanism. An alternative allocation mechanism may apply if the default mechanism of auction is not appropriate, and if certain conditions are met. It is possible to adjust the tariff by applying a mandatory minimum premium in case the sole application of a reference price cannot guarantee the economic viability of an incremental project.

Figure 35 describes the incremental process in general, while Figure 36 provides a more detailed overview. In 2017 the first market demand assessment for incremental capacity must be conducted as from the entry into force of the Amended CAM NC. In the following years, the market demand assessment begins immediately after the start of the annual yearly capacity auctions.

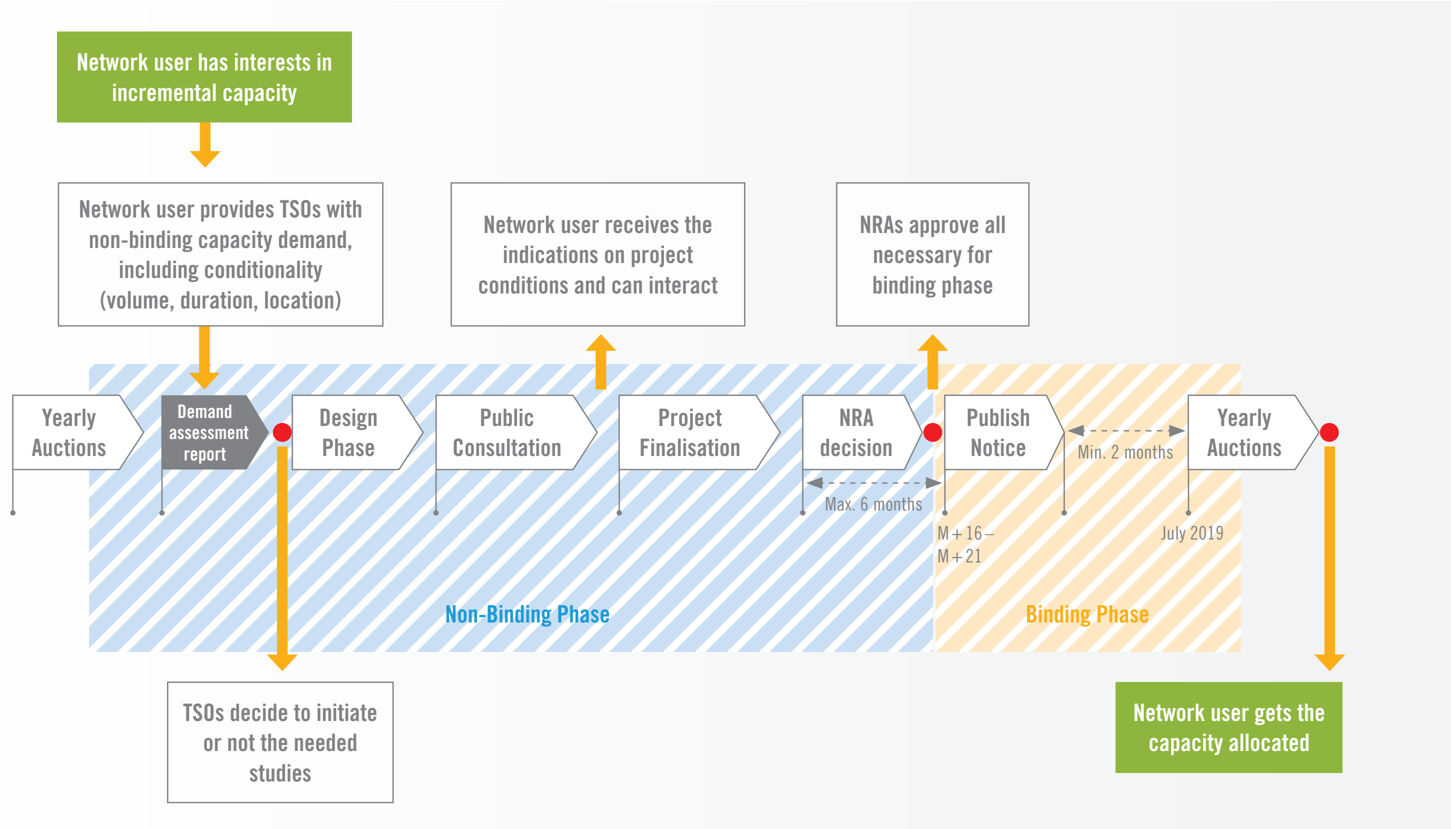


Figure 35: General description of incremental process

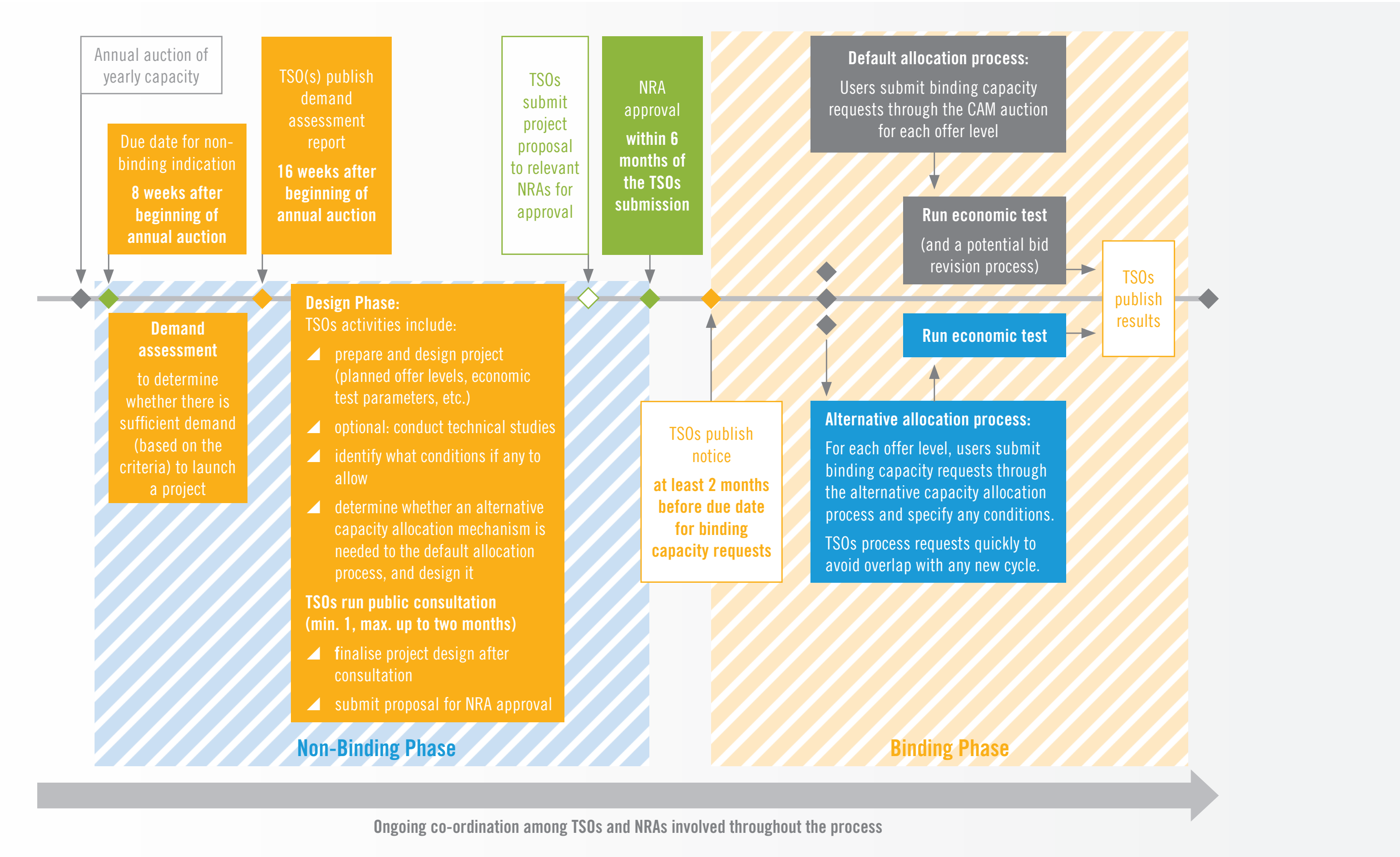


Figure 36: Detailed description of incremental process

ARTICLE 33 TARIFF PRINCIPLES FOR INCREMENTAL CAPACITY

Responsibility: TSO/NRA responsibility: TSOs submit the project proposal to NRAs; NRAs take and publish coordinated decisions on the project proposal

Adjustment of the reference price

The reference price is the minimum price at which TSOs must accept a request for incremental capacity. For the calculation of the economic test, reference prices must be determined by including all relevant assumptions related to the offer of incremental capacity into the RPM.

If a fixed payable price approach is proposed for the incremental capacity and approved by the NRA, then the reserve price must be based on projected investment and operating costs. Once the incremental capacity is commissioned, the reserve price must be adjusted proportionally to reflect the difference between the projected investment costs and the actual investment costs, regardless of a positive or negative difference. Figures 37 and 38 show two examples of adjustments to the reference price.

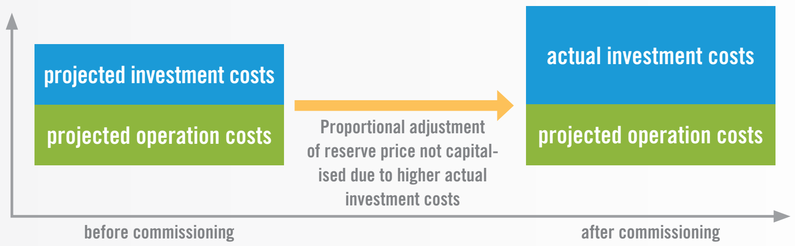


Figure 37: Adjustment of the reference price where the projected investment costs are lower than actual investment costs in case of fixed payable price

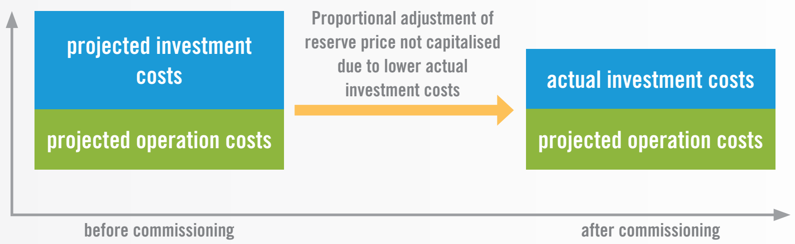


Figure 38: Adjustment of the reference price where the projected investment costs are higher than actual investment costs in case of fixed payable price

Mandatory minimum premium

The incremental process introduced the concept of the mandatory minimum premium to facilitate the satisfaction of the economic test if the reference price resulting from the RPM would not generate sufficient revenue. Figure 39 shows the components of the economic test.

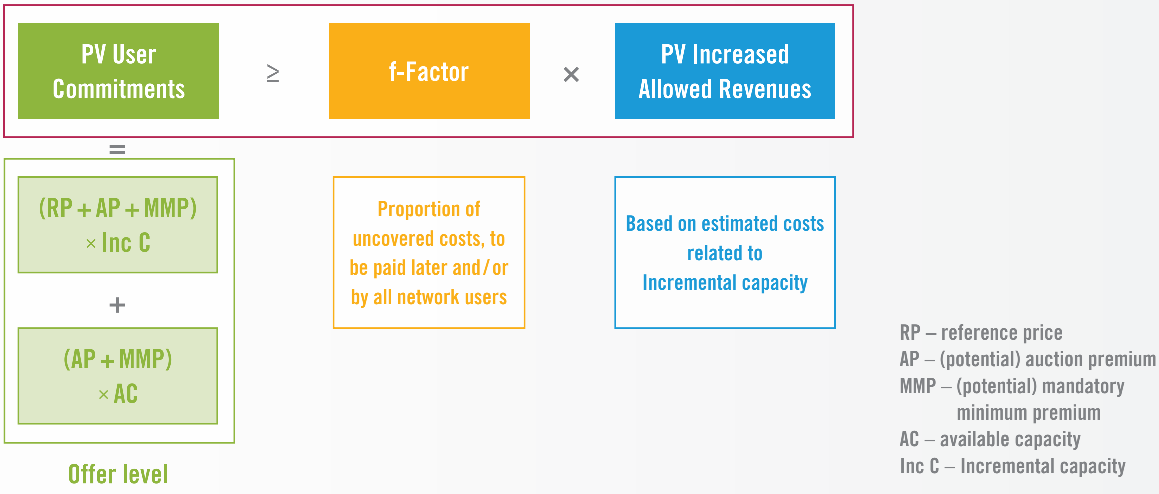


Figure 39: Components of economic test

When incremental capacity is offered, the mandatory minimum premium may be applied in the first auction or in an alternative allocation mechanism. The mandatory minimum premium may also be applied in subsequent auctions when:

- The offered capacity was initially set aside for the annual quarterly capacity auctions; or
- The offered capacity initially remained unsold.

The level of the mandatory minimum premium must allow the project to pass the economic test with the revenues generated by the allocation of all offered capacity in the first auction in which the incremental capacity is on offer. The range of the level for the mandatory minimum premium depends on the expected amount of allocated capacity, and must be submitted to the NRA for approval. The decision whether and in which auctions to apply a mandatory minimum premium must consider Article 41(6)(a) of the Gas Directive.

In contrast to the possible split of a potential auction premium between all involved TSOs, the mandatory minimum premium must only be allocated to the TSO for which the applied mandatory minimum premium was approved.

Chapter X: Final and Transitional Provisions

Chapter X 'Final and Transitional Provisions' of the TAR NC has the following structure: Articles 34 to 37 are 'miscellaneous' provisions not addressed elsewhere in the TAR NC: ACER's report on methodologies and parameters to determine the TSOs' allowed/target revenue, protection of some existing contracts, implementation monitoring and derogations for interconnectors; Article 38 elaborates on 'entry into force and application dates' of the TAR NC.


Image courtesy of FGSZ

Summary

Scope: IPs and non-IPs
Application date: entry into force (6 April 2017)

The TAR NC requires ACER to produce a report on the **methodologies and parameters used to determine the allowed/target revenue of TSOs**. To that end, the NRAs must submit the relevant information to ACER.

This Chapter also addresses the grandfathering of the capacity- and/or commodity tariff level for **existing contracts**. A contract must meet two requirements to become eligible for grandfathering: conclusion before the entry into force of the TAR NC, and the exclusion of any change in tariff level other than indexation. Such contracts must be sent to the NRA for information.

Following the precedent of the INT NC, the TAR NC contains some specific provisions on ENTSOG's **implementation monitoring**, such as deadlines for the TSOs' submission of information to ENTSOG, and for ENTSOG's reporting to ACER.

In addition, the TAR NC sets out the detailed procedure for dealing with the specificity of **interconnectors**.

The last Article of the TAR NC includes 3 different **ADs** for different Chapters:

- Chapters I, V, VII, IX and X: entry into force = 6 April 2017;
- Chapters VI and VIII: 1 October 2017;
- Chapters II, III and IV: 31 May 2019.

Miscellaneous

ARTICLE 34 METHODOLOGIES AND PARAMETERS USED TO DETERMINE THE ALLOWED/TARGET REVENUE

Responsibility: NRA's submits information to ACER; ACER produces report

The allowed/target revenue is a basic element of tariff design. ACER must produce a report on methodologies and parameters to determine the allowed/target revenue, for publication within two years after the TAR NC enters into force. The TAR NC obligates the NRAs to submit to ACER the information on methodologies and parameters to determine TSOs' allowed/target revenues. ACER must set in advance the process for gathering such information.

The minimum content of such a report is the information set out in Article 30(1)(b)(iii) of the TAR NC, which includes: (1) types of assets included in the regulated asset base and their aggregated value; (2) cost of capital and its calculation methodology; (3) capital expenditures, including methodologies to determine the initial value of the assets, methodologies to re-evaluate assets, explanations of the evolution of the value of the assets and depreciation periods and amounts per asset type; (4) operational expenditures; (5) incentive mechanisms and efficiency targets; and (6) inflation indices.

EXISTING CONTRACTS

ARTICLE 35

Responsibility: no implications for TSO/NRA responsibility

Legitimate expectations

The TAR NC 'grandfathers' or protects the tariff level in some existing fixed price contracts. The application of the TAR NC to certain existing contracts would undermine the principle of legal certainty and legitimate expectations.

Existing contracts must satisfy three criteria to qualify for grandfathering:

- Type: only fixed price contracts qualify, not floating price contracts since their signatories foresaw future price changes.
- Extent: only the transmission tariff level qualifies for exemption. In principle, the TAR NC will apply to fixed price contracts, but not to their transmission tariff level. Grandfathering extends both to capacity- and to commodity-based transmission tariffs.
- Time: the 'existing' fixed price contracts must have been concluded before the TAR NC entered into force. Qualifying contracts cannot extend their grandfathering through renewal or extension after their termination date.

Capacity-/commodity-based transmission tariffs in grandfathered contracts

Some MSs have grandfathered contracts that fix capacity- and/or commodity-based transmission tariffs for their entire duration, except for regular indexation. The tariffs in such qualifying contracts are not subject to any future changes of the regulatory framework:

- For capacity-based transmission tariff: (1) if the exact 'initial' level is fixed (Great Britain); (2) if the exact 'initial' level and the indexation formula is fixed (the Czech Republic, Slovakia);
- For commodity-based transmission tariff, if the exact level is fixed as a percent of transported gas, which is not subject to indexation (the Czech Republic, Slovakia).

IMPLEMENTATION MONITORING

ARTICLE 36

Responsibility: TSOs send information to ENTSOG; ENTSOG produces the monitoring reports and sends them to ACER; ACER produces a report on RPMs

Article 8(8) of the Gas Regulation requires ENTSOG each year to *'monitor and analyse the implementation of the NCs and the Guidelines adopted by the Commission in accordance with Article 6(11), and their effect on the harmonisation of applicable rules aimed at facilitating market integration'*. Article 8(8) also requires ENTSOG to *'report its findings to the Agency and […] include the results of the analysis in the annual report'*. The content of these ENTSOG's reports is connected with the specific ADs. That is, each report would cover different Chapters depending on a specific AD. Chapter VIII 'Publication requirements', depends on the applied tariff period, as compliance with this Chapter takes place after its entry into force as explained in Part 1 above, indicated in orange in Figure 40.

Article 36 of the TAR NC sets out specific deadlines for TSOs to provide ENTSOG information, and for ENTSOG to report to ACER in 2018 and 2020, as shown in green in Figure 40. While the specific reporting deadlines involve only two years, annual monitoring and reporting activity implies an additional report in 2019, shown in Figure 40. Figure 40 does not show the 2021 monitoring report, since it does not fall explicitly or implicitly under Article 36 as linked to implementation, and would therefore cover only the 'effect' component of monitoring as opposed to implementation. Figure 40 shows in grey the indicative content of ENTSOG's monitoring reports, with three purple crosses indicating the deadlines for their preparation.

ENTSOG's first TAR NC monitoring report (by 31 March 2018):

For **implementation monitoring**, this report will cover the TAR NC Chapters with AD 1 as well as partially Chapter VIII 'Publication requirements'. Although the AD of Chapter VIII is 1 October 2017, compliance with its obligations occurs later as explained in Part 1 above[1]. The deadline of 31 December 2017 for the provision of information by TSOs to ENTSOG will only be met for compliance by TSOs with an obligation to publish tariff information before the tariff period January–December. For other tariff periods, compliance will not be possible as the deadline of 31 December 2017 precedes the deadlines of March, June and September 2018 for publishing information before the tariff period. The same applies for publishing information before the annual yearly capacity auctions as the deadline of 31 December 2017 precedes the deadline of June 2018. The next ENTSOG monitoring report will address the obligation to publish tariff information before other tariff periods as well as compliance with an obligation to publish tariff information before the annual yearly capacity auctions. For **effect monitoring**, the same report will cover indicators used for all the TAR NC as well as the data for such indicators as of March 2018.

ENTSOG's second TAR NC monitoring report (by March/April 2019):

For **implementation monitoring**, this report will cover the TAR NC Chapters with AD 2, including compliance with obligations under Chapter VIII 'Publication requirements' which are not covered in the first monitoring report. For **effect monitoring**, this report will cover the indicators used for all the TAR NC, which could be the same as outlined in the first monitoring report, or could entail modification or expansion, as well as the data for such indicators as of March 2019 compared with March 2018.

ENTSOG's third TAR NC monitoring report (by 31 March 2020):

For **implementation monitoring**, this report will cover the TAR NC Chapters with AD 3. Article 36 foresees that by default, this is the last ENTSOG monitoring report that covers implementation monitoring. ENTSOG can only continue to monitor implementation if the EC makes a corresponding request. As ENTSOG's fourth TAR NC monitoring report is scheduled for March 2021, the EC should make any such request sufficiently in advance. For **effect monitoring**, this report will cover indicators used for all the TAR NC, which could be the same as outlined in the first or second monitoring reports, or could entail modification or expansion, as well as the data for such indicators as of March 2020 compared with March 2019 and March 2018, to convey any trend associated with TAR NC implementation.

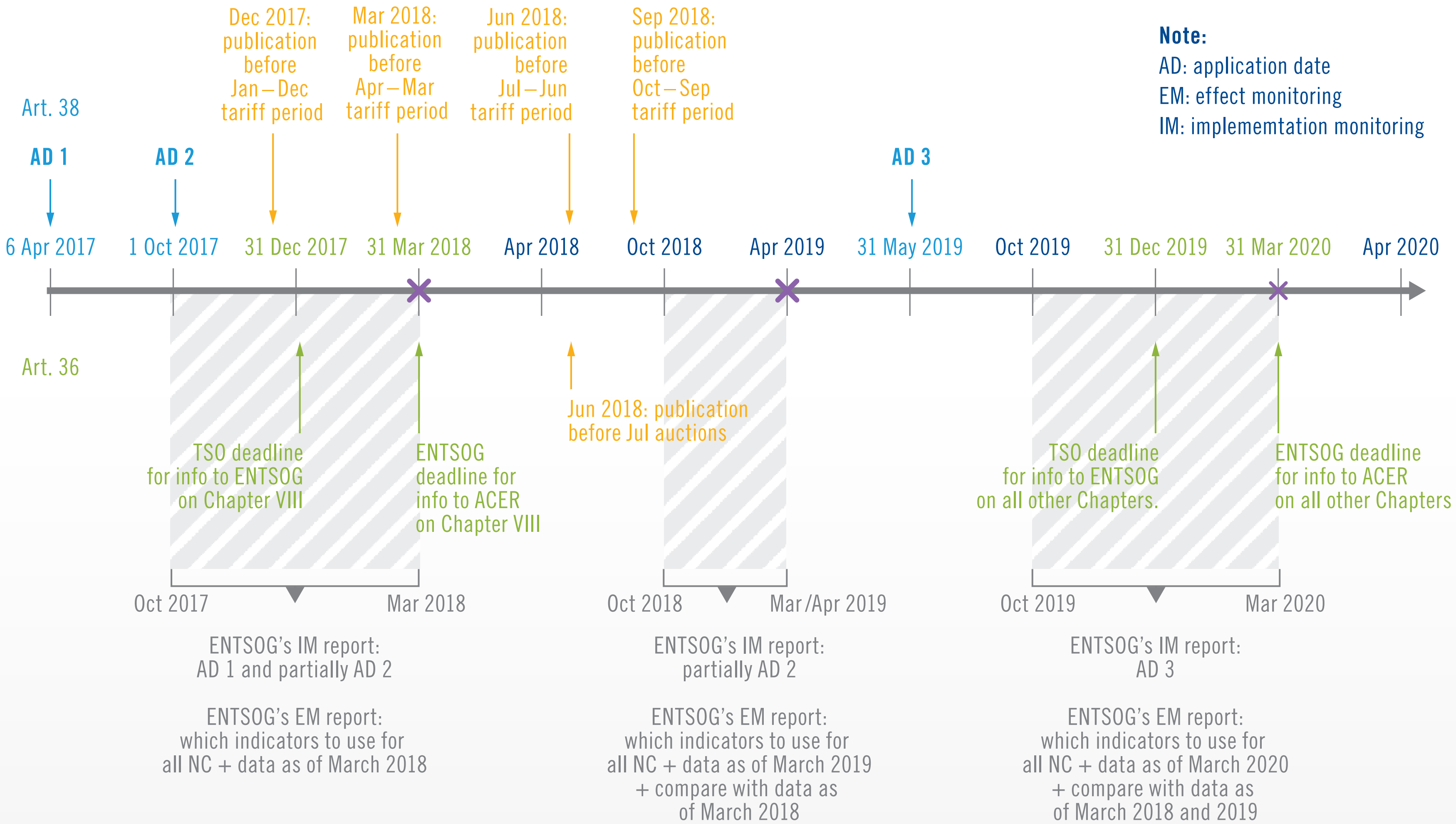
ENTSOG's fourth TAR NC monitoring report (by 31 March 2021):

For **effect monitoring**, this report will cover indicators used for all the TAR NC, applying discretion on their selection or modification in the same manner as previous monitoring reports, as well as the data for such indicators as of March 2021 for comparison with previous years to indicate any trends.

The effect monitoring will continue after 2020 following the same timescales for the monitoring report preparation. It is subject to further discussion when ENTSOG should stop producing effect monitoring reports.

1) See Chapter VIII 'Publication requirements', Section 'Article 31 – publication notice period'.

Figure 40: ENTSOG's timeline for TAR NC monitoring



ARTICLE 37 POWER TO GRANT DEROGATIONS

Responsibility: subject to NRA decision

General

Article 37 recognises that interconnectors are a distinct type of a TSO. The specific nature of interconnectors might warrant exemption from some of the Articles in the TAR NC. Article 37 allows interconnectors meeting certain criteria to apply for and be granted a derogation from one or more Articles of the TAR NC granted by the relevant NRAs.

The Gas Directive distinguishes between transmission networks and interconnectors. Article 2(17) of that Directive defines an 'interconnector' as *'a transmission line which crosses or spans a border between MSs for the sole purpose of connecting national transmission systems of those MSs'*. Such interconnectors' characteristics include:

- They are single pipelines with very few entry/exit points;
- They have no captive demand, that is no directly connected end-user demand;
- They are not directly connected to downstream distribution networks;
- They may compete directly with other assets such as storage, LNG and other pipelines in providing flexibility to the connected transmission networks;
- They may be merchant assets without an allowed or target revenue set in accordance with Article 41(6)(a) of the Gas Directive.

Process for granting a derogation from the TAR NC

Figure 41 shows the process for applying and assessing a derogation from the TAR NC. A derogation can cover all or some of the TAR NC provisions subject to NRA decision. The TAR NC does not foresee any explicit time limit for such a derogation.

The process starts with a request from an entity operating an interconnector to the relevant NRAs. Such an interconnector must be the one that *'has benefited from'*: (1) an exemption from Article 41(6), (8) and (10) of the Gas Directive in accordance with Article 26 of the Gas Directive; or (2) *'a similar exemption'*. The applicant must demonstrate all/some TAR NC provisions would have one or several of the following negative consequences:

(1) not facilitating efficient gas trade and competition;

(2) not providing incentives for investing in new capacity or for maintenance of existing capacity;

(3) unreasonable distortion of cross-border trade;

(4) distortion of competition with other infrastructure operators offering similar to interconnector services; and

(5) not being implementable when taking into account the specific nature of interconnectors.

This list of consequences included in Article 37(2) of the TAR NC is exhaustive – however, meeting one of them suffices for a derogation request. The interconnector requesting a derogation must provide detailed reasoning, supporting documents and, where appropriate, a CBA. Such CBA must demonstrate one or more negative consequences listed in point (1) to (5) above.

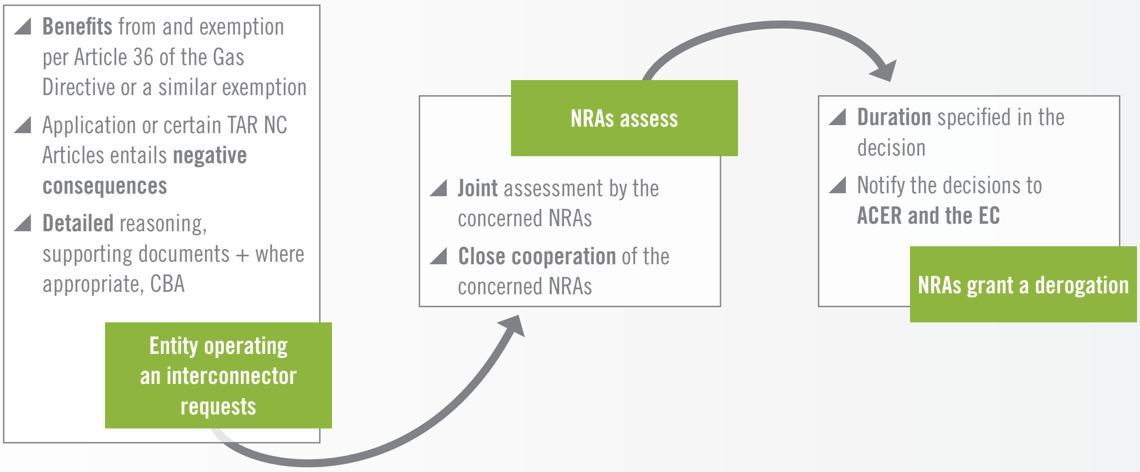


Figure 41: Process for granting a derogation from the TAR NC to interconnectors

The relevant NRAs must then assess the received request jointly and in cooperation with each other. If they conclude that a derogation can be granted, their decision must specify its duration. Such decisions must be sent to ACER and the EC for information. The relevant NRAs can subsequently revoke a derogation either on their own initiative if the negative consequence(s) and/or the reasoning for such derogation cease to be valid, or upon a reasoned recommendation of ACER/the EC to revoke the derogation due to lack of justification.

Entry into Force and Application Dates

ARTICLE 38 ENTRY INTO FORCE

Responsibility: no implications for TSO/NRA responsibility

Entry into force date

Article 38 does not explicitly state the date for entry into force, but the date is 20 days after publication of the TAR NC in the Official Journal of the EU, which is 6 April 2017 calculated as form 17 March 2017. 'Entry into force' means that the TAR NC provisions have become legally binding.

Application dates

As compared to the 'entry into force' date, 'application date' is linked to the date for compliance with the TAR NC provisions.

The TAR NC foresees three different ADs for its different Chapters (shown in Figure 42):

- AD 1 – entry into force (6 April 2017) for the following Chapters: Chapter I 'General provisions', Chapter V 'Pricing of bundled capacity and capacity at VIPs', Chapter VII 'Consultation requirements', Chapter IX 'Incremental capacity' and Chapter X 'Final and transitional provisions';
- AD 2 – 1 October 2017 for the following Chapters: Chapter VI 'Clearing and payable price' and Chapter VIII 'Publication requirements';
- AD 3 – 31 May 2019 for the following Chapters: Chapter II 'Reference price methodologies', Chapter III 'Reserve prices', Chapter IV 'Reconciliation of revenue'.

AD 1 coincides with the entry into force date. Article 38 sets AD 1 as a default AD, while AD 2 and 3 are viewed as exceptions.

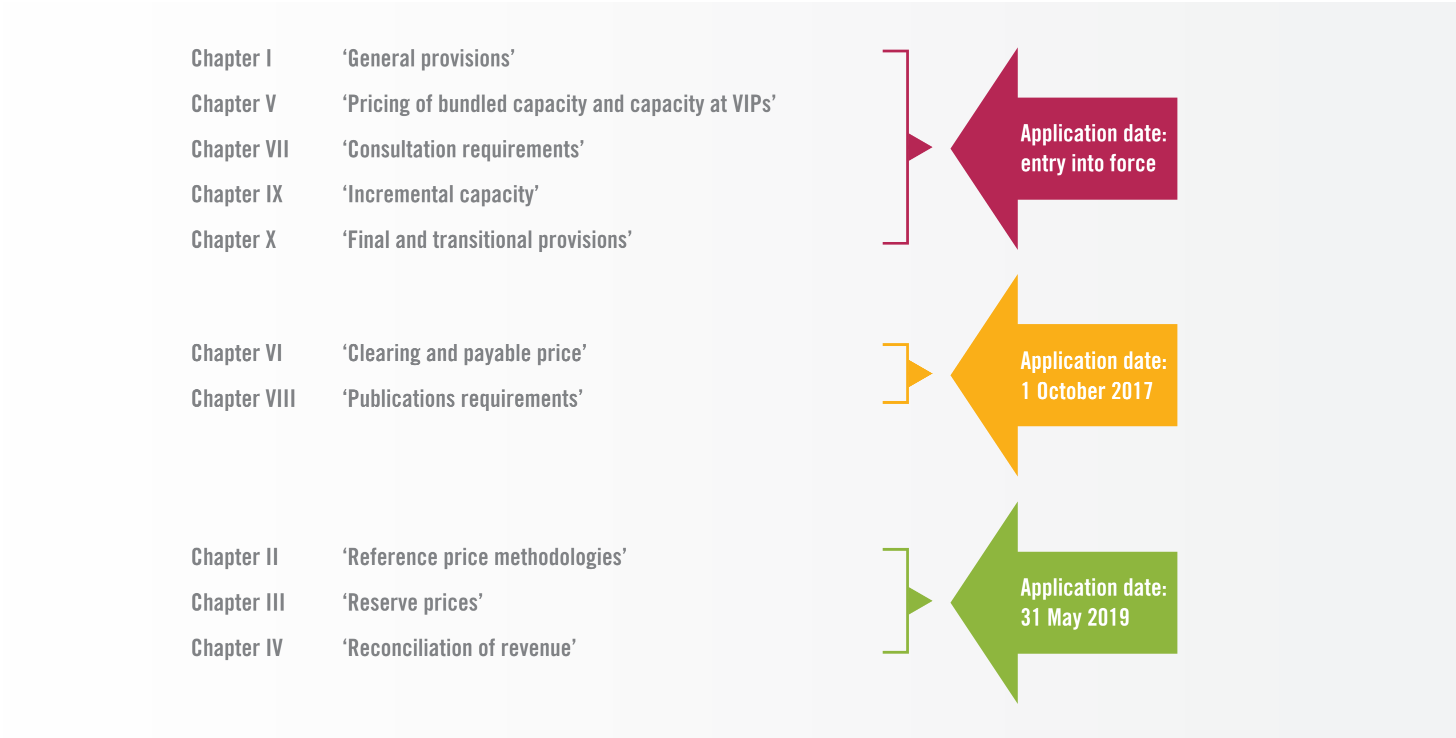


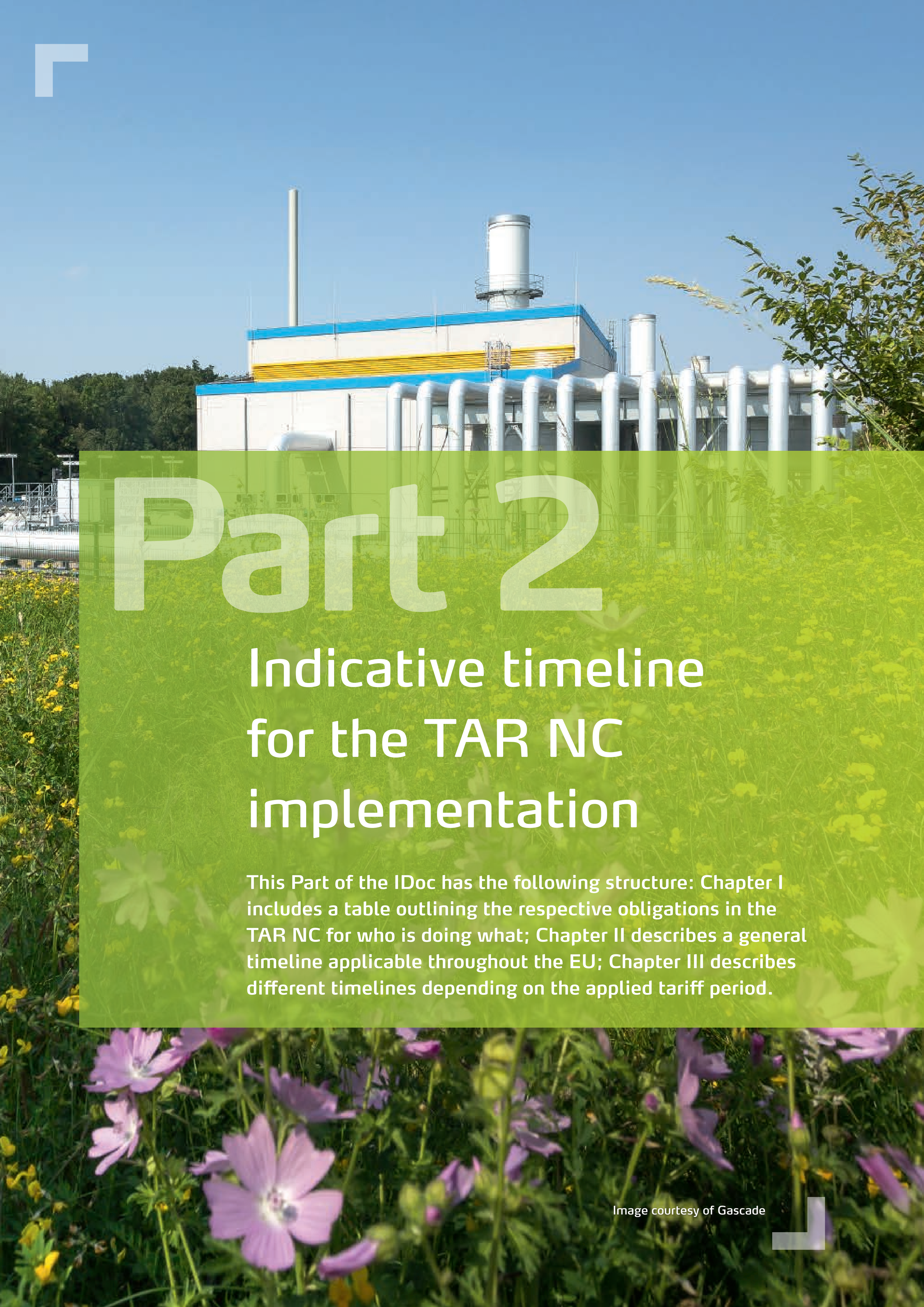
Figure 42: TAR NC application dates

Although two specific rules in the listed Chapters have established ADs, the TAR NC allows compliance at a later date:

- The AD for Chapter II 'Reference price methodologies' is 31 May 2019 – but Article 27(5) permits retaining tariffs applicable at such date until the end of the prevailing tariff period. Therefore, the compliance date is later than the AD, due to different tariff periods applicable across the EU[1].
- The AD for Chapter VIII 'Publication requirements' is 1 October 2017 – but compliance with publication requirements depends on the date of the auctions and on the applicable tariff period. Therefore, the compliance date is later than the AD. For one obligation the compliance date is linked to the auction date; for the other obligation, the compliance date differs due to different tariff periods applicable across the EU[2].

1) See Chapter VII 'Publication Requirements', Section 'Article 27(5) – 'new' tariffs'.

2) See Chapter VIII 'Publication Requirements', Section 'Article 31 – publication notice period'.



Part 2

Indicative timeline for the TAR NC implementation

This Part of the IDoc has the following structure: Chapter I includes a table outlining the respective obligations in the TAR NC for who is doing what; Chapter II describes a general timeline applicable throughout the EU; Chapter III describes different timelines depending on the applied tariff period.

Image courtesy of Gascade

Chapter I:
Who Is Doing What

Table 16 includes the obligations in the TAR NC by 'actor': TSO/NRA, TSO, NRA, ENTSOG, ACER and the EC. The obligations are listed in the order of their appearance in the TAR NC.

The obligations highlighted in blue are not in Chapter II 'General timeline' below. The obligations with an asterisk are only indicated on the timeline for 'Multi-TSO arrangements within a MS' in Chapter II 'General timeline' below.

WHO IS DOING WHAT

Who	Ref. to the NC	What to do	When to do	Application Date
I. TSO/NRA, as decided by NRA	1. Article 5(1), ref. to Article 26	Perform and publish CAA as part of the final consultation per Article 26	Part of the final consultation per Article 26	Rule – 6 April 2017, compliance – 31 May 2019
	2. Article 26	Carry out the periodic consultations: one or more 'intermediate' consultations (optional, covers some/all elements in Article 26(1)) + final consultation (obligatory, covers all elements in Article 26(1)) Prepare consultation document(s) in English, to the extent possible	As from the NC entry into force Min duration of consultation – 2 months	Rule – 6 April 2017, compliance – 31 May 2019
	3. Article 26(3)	Publish the responses and their summary from the consultation referred to in point 2 Prepare the summary in English, to the extent possible	Within 1 month following the end of consultation referred to in point 2	Rule – 6 April 2017, compliance – 31 May 2019
	4. Article 27(1)	Forward the final consultation document(s) to ACER	Upon launching the final consultation and prior to decision referred to in point III.18	Rule – 6 April 2017, compliance – 31 May 2019
	5. Article 29	Publish the information before the annual yearly capacity auction	Min 30 days before the annual yearly capacity auction	Rule – 1 October 2017, compliance – June 2018 and every year thereafter
	6. Article 30	Publish the information before the tariff period	Min 30 days before the tariff period	Rule – 1 October 2017, compliance – depending on the tariff period and every year thereafter
II. TSO	1. Article 21(3)	Agree on the attribution of the auction premium from the sales of bundled capacity products (unless such agreement is in place and approved)	Before the approval referred to in point III.14, not a yearly activity unless there are changes to the agreement	6 April 2017
	2. Article 35(3)	Send the contracts or the information on capacity bookings to NRA for information – where the transmission tariff level foreseen in such contracts is grandfathered	Within 1 month as from the NC entry into force	Rule – 6 April 2017, compliance – 6 May 2017
	3. Article 36(2)(a)	Submit to ENTSOG all information required by ENTSOG as regards to compliance with Chapter VIII of the NC	31 December 2017	Rule – 6 April 2017, compliance – 31 December 2017
	4. Article 36(2)(b)	Submit to ENTSOG all information required by ENTSOG as regards to compliance with Chapters other than Chapter VIII of the NC	31 December 2019	Rule – 6 April 2017, compliance – 31 December 2019
	5. Article 37(1)-(2)	Request an exemption from one/more NC Articles, include in the request a detailed reasoning, supporting documents and, where appropriate, CBA	As from entry into force	Rule – 6 April 2017, compliance – depending on the date of application for an exemption

WHO IS DOING WHAT

Who	Ref. to the NC	What to do	When to do	Application Date
III. NRA	1. Article 5(6), ref. to Article 27(4)	Provide justification for capacity/commodity cost allocation comparison indexes exceeding 10 %	Part of the decision per Article 27(4)	Rule – 6 April 2017, compliance – 31 May 2019
	2. Article 6(1), ref. to Article 27	Set or approve the RPM	Per Article 27	31 May 2019
	3. Article 10(2)(a)*	Decide that the same RPM is applied separately in a multi-TSO entry-exit system within a MS	Estimate – together with the decision per Article 27(4)	31 May 2019
	4. Article 10(2)(b)*	Decide on intermediate steps allowing for different RPM to be applied separately in a multi-TSO entry-exit system within a MS – when planning entry-exit system mergers	Estimate – together with the decision per Article 27(4)	31 May 2019
	5. Article 10(2)(b)*	Decide who carries out an impact assessment and a CBA on intermediate steps referred to in point 4 – TSO or NRA	Before the decision referred to in point 4	31 May 2019
	6. Article 10(2)(b)*	Carry out an impact assessment and a CBA on intermediate steps referred to in point 4	Before the decision above in point 4 and after the decision referred to in point 5	31 May 2019
	7. Article 10(4)	Decide whether to postpone the initial deadline for applying the RPM(s) separately referred to in point 3 or 4	Before the deadline set out in the decision referred to in point 3 or 4	31 May 2019
	8. Article 10(5)*	Carry out a consultation on the principles of an effective ITC and its consequences on the tariff level	Simultaneously with the final consultation per Article 26	31 May 2019
	9. Article 10(5)*	Publish the ITC mechanism and the responses to the consultation on the principles of an effective ITC and its consequences on the tariff level	After the consultation referred to in point 8	31 May 2019
	10. Article 19(3)	Decide whether to implement incentive mechanisms for capacity sales	Estimate – before the start of the regulatory/tariff period	31 May 2019
	11. Article 19(5)	Decide whether to attribute the earned auction premium to a specific account separate from the regulatory account	Estimate – before the start of the regulatory/tariff period	31 May 2019
	12. Article 19(5)	Decide whether to use the earned auction premium to reduce physical congestion – applicable for both price cap and non-price cap regimes Decide whether to use the earned auction premium to decrease the transmission tariffs for the next tariff period(s) – applicable only for non-price cap regimes	Estimate – before the start of the regulatory/tariff period	31 May 2019
	13. Article 20(2)	Decide on the rules for reconciliation of the regulatory account	Estimate – before the start of the regulatory period	31 May 2019
	14. Article 21(3)	Approve the agreement between TSOs on the attribution of the auction premium from the sales of bundled capacity products referred to in point II.1	No later than 3 months before the start of the annual yearly capacity auctions, not a yearly activity unless there are changes to the agreement	Rule – 6 April 2017, compliance – March 2018
	15. Article 21(4)	Submit the agreement referred to in point 14 to ACER for information – when the IP connects adjacent entry-exit systems of two MSs	Once the agreement is approved; for agreements in place before the TAR NC – after entry into force	6 April 2017
	16. Article 26(1)	Decide who carries out the periodic consultation – TSO or NRA	As from the NC entry into force	6 April 2017
	17. Article 27(1)	Decide who will forward the consultation documents referred to in point I.2 to ACER – TSO or NRA	Upon launching the final consultation	Rule – 6 April 2017, compliance – 31 May 2019
	18. Article 27(4)	Take and publish a motivated decision on all the elements in Article 26(1) Send this decision to ACER and the EC	Within 5 months as from the end of the final consultation	Rule – 6 April 2017, compliance – 31 May 2019
	19. Article 28(1)	Consult NRAs from directly connected MSs and relevant stakeholders on multipliers, seasonal factors, interruptible discounts, LNG discounts and 'isolation' discounts	At the same time as the final consultation per Article 26(1)	Rule – 6 April 2017, compliance – 31 May 2019
	20. Article 28(1), (3)	Consider the positions of NRAs from directly connected MSs, take into account the consultation responses Take a decision on multipliers, seasonal factors, interruptible discounts, LNG discounts and 'isolation' discounts	After the consultation referred to in point 19, estimate – together with the decision per Article 27(4)	Rule – 6 April 2017, compliance – 31 May 2019
	21. Article 28(2)	Consult NRAs from directly connected MSs and relevant stakeholders on multipliers, seasonal factors interruptible discounts, LNG discounts and 'isolation' discounts	Every tariff period as from the date of the decision referred to in point 20	Every tariff period after the initial NRA decision taken by 31 May 2019

WHO IS DOING WHAT

Who	Ref. to the NC	What to do	When to do	Application Date
III. NRA	22. Article 28(2)	Take a decision on multipliers, seasonal factors interruptible discounts, LNG discounts and 'isolation' discounts	After the consultation referred to in point 21 before the publication of tariff information no later than 30 days before the annual yearly capacity auction	Every tariff period after the initial NRA decision taken by 31 May 2019
	23. Article 29	Decide who publishes the information before the annual yearly capacity auction – TSO or NRA	As from NC entry into force	1 October 2017
	24. Article 30	Decide who publishes the information before the tariff period – TSO or NRA	As from NC entry into force	1 October 2017
	25. Article 34(2)	Submit to ACER all necessary information related to methodologies and parameters to determine the allowed/target revenue of TSOs	Within 2 years as from the NC entry into force	Rule – 6 April 2017, compliance – within 2 years as from the NC entry into force
	26. Article 37(3)-(4)	Assess the request per point II.5, grant a derogation, specify the duration in the decision, notify the decision to ACER and the EC	As soon as possible after the receipt of the request	Rule – 6 April 2017, compliance – later
	27. Article 37(5)	Revoke the derogation granted as referred to in point 26	When circumstances/reasons no longer apply or upon EC/ACER recommendation	Rule – 6 April 2017, compliance – later
IV. ACER	1. Article 13(3)	(Optional) Issue a recommendation that the maximum level of multipliers for daily and within-day standard capacity products should be reduced to no more than 1.5	By 1 April 2021	Impact on multiplier level – by 6 April 2023
	2. Article 26(5)	Consult ENTSOG, develop and make available a template for the consultation document referred to in point I.2	By 5 July 2017	Rule – 6 April 2017, compliance – 5 July 2017
	3. Article 27(2)	Analyse the listed aspects of the final consultation document	From the date of receiving the final consultation document until the date calculated as 2 months as from the end of the final consultation	Rule – 6 April 2017, compliance – 31 May 2019
	4. Article 27(3)	Publish and send to the TSO/NRA and the EC the conclusion of ACER analysis, in English	Within 2 months as from the end of the final consultation	Rule – 6 April 2017, compliance – 31 May 2019
	5. Article 34(1)	Publish a report on the methodologies and parameters used to determine the allowed/target revenue of TSOs	Within 2 years as from the NC entry into force	Rule – 6 April 2017, compliance – 6 April 2019
	6. Article 34(2)	Define procedure for NRAs' submission of information	Before point 5	Rule – 6 April 2017, compliance – 6 April 2019
	7. Article 36(5)	As part of implementation monitoring, publish a report on the application of the RPMs in MSs	Within 3 years as from the NC entry into force	Rule – 6 April 2017, compliance – 6 April 2020
	8. Article 37(5)	(Optional) Recommend to revoke the NRA derogation referred to in point III.26 – due to a lack of justification	Due to a lack of justification for applying a derogation	Rule – 6 April 2017, compliance – later
V. ENTSOG	1. Article 31(1)	Provide a link on ENTSOG's TP to the website of TSO/NRA with information per Article 29 and 30	Min 30 days before the annual yearly capacity auction Min 30 days before the tariff period	Rule – 1 October 2017, compliance – June 2018 and every year thereafter Rule – 1 October 2017, compliance – depending on the tariff period and every year thereafter
	2. Article 31(2)	Ensure the publication directly on ENTSOG's TP for: reserve prices for firm/interruptible standard capacity products, flow-based charge and simulation of all the costs for flowing 1GWh/day/year	Min 30 days before the annual yearly capacity auction Min 30 days before the tariff period	Rule – 1 October 2017, compliance – June 2018 and every year thereafter Rule – 1 October 2017, compliance – depending on the tariff period and every year thereafter
	3. Article 36(1)(a)	Monitor and analyse how TSOs implemented Chapter VIII of the NC, submit information to ACER	31 March 2018	Rule – 6 April 2017, compliance – 31 March 2018
	4. Article 36(1)(b)	Monitor and analyse how TSOs implemented Chapters other than Chapter VIII of the NC, submit information to ACER	31 March 2020	Rule – 6 April 2017, compliance – 31 March 2020
VI. EC	1. Article 36(3)	(Optional) Request that the implementation monitoring cycle as set out in Article 36(1) and 36(2) must be repeated in forthcoming years	Later than 31 March 2020 and sufficiently in advance of March 2021	Rule – 6 April 2017, compliance – later than 31 March 2020 and sufficiently in advance of March 2021
	2. Article 37(5)	(Optional) Recommend to revoke the NRA derogation referred to in point III.26 – due to a lack of justification	Due to a lack of justification for applying a derogation	Rule – 6 April 2017, compliance – later

Table 16: Who is doing what

Chapter II: General Timeline

The colour code in the Figures below is as follows:

- **Purple** indicates information on the three application dates of the TAR NC;
- **Grey** indicates tariff information for an individual tariff period required for publication by TSOs/NRAs;
- **Yellow** indicates tariff information for July auctions required for publication by TSOs/NRAs;
- **Red** is for the indication of the annual yearly capacity auctions in July under the CAM NC;
- **Blue** is for actions required from ACER;
- **Green** is for implementation and effect monitoring tasks for TSOs and ENTSOG;
- **Orange** is for other tasks for TSOs, NRAs, TSOs/NRAs; and
- **White** with an orange outline is for estimated completion dates of the tasks for NRAs, TSOs/NRAs.

For the actions related to the final consultation, Chapter VII 'Consultation requirements', Article 26(2)-(3) and Article 27 'Procedure for periodic consultation' indicate that ENTSOG has estimated December 2017 as the start date for preparing the final consultation document. Such a start will allow sufficient time to conduct a final consultation, to have the new RPM approved by the NRA, and to have new tariffs calculated and published by the deadline of 31 May 2019 envisaged in the TAR NC. Therefore, the estimated timelines in this Chapter show the process steps regarding the final consultation as from December 2017.

CALENDAR YEAR 2017

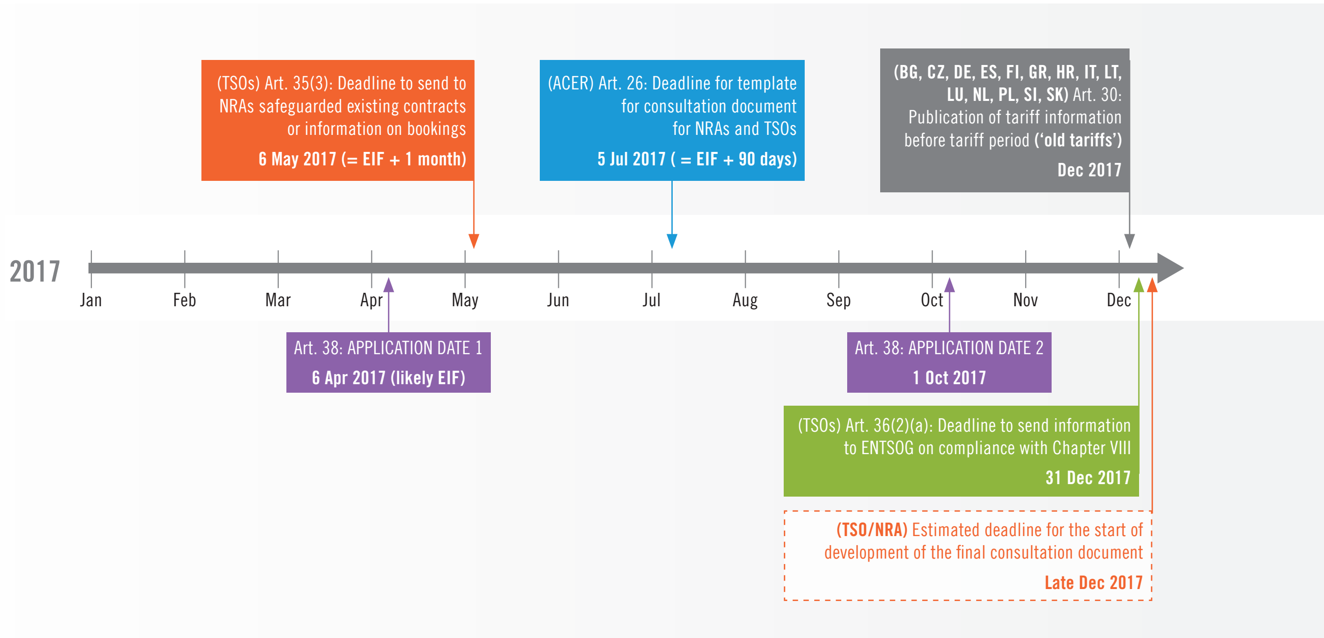


Figure 43: General timeline for 2017

Purple boxes: The calendar year 2017 includes two out of the three ADs of the TAR NC, namely: (1) 6 April 2017 (entry into force date, 'AD 1') for Chapter I 'General provisions', Chapter V 'Pricing of bundled capacity and capacity at VIPs', Chapter VII 'Consultation requirements', Chapter IX 'Incremental capacity' and Chapter X 'Final and transitional provisions'; and (2) 1 October 2017 (explicitly mentioned in the TAR NC, 'AD 2') for Chapter VI 'Clearing and payable price' and Chapter VIII 'Publication requirements'.

Orange box: Within 1 month as from AD 1, the TSOs are obliged to send to the NRA the existing contracts or information on capacity bookings eligible for grandfathering under the TAR NC, which foresee no change of the level of capacity- and/or commodity-based transmission tariffs, except for indexation, if any (Article 35(3) of the TAR NC).

Blue box: By 5 July 2017, ACER is obliged to make available to TSOs and NRAs a template for the consultation document per Article 26(1), after having consulted ENTSOG (Article 26(5) of the TAR NC).

Grey box: As explained in Part 1, Chapter VIII 'Publication requirements', AD 2 for the TAR NC Chapter VIII 'Publication requirements' does not mean that the tariffs will be published at this date[1]. The first compliance with the obligation in the TAR NC Chapter VIII 'Publication requirements' will be for MSs with tariff period January–December, for publication of the set of information before the tariff period, on TSO/NRA website, as decided by the NRA (Article 30 of the TAR NC). Simultaneously, a link to such information will be provided on ENTSOG's TP and also, the flow-based charge (if applied) and simulation of all the costs for flowing 1 GWh/day/year will be published directly on ENTSOG's TP in a standardised table, for IPs only. Tariffs will be derived following the 'old' RPM as the requirement for the 'new' RPM is only applicable as of AD 3 of 31 May 2019.

Green box: The TAR NC sets out an obligation for TSOs to submit to ENTSOG the information on their compliance with Chapter VIII 'Publication requirements' by 31 December 2017 (Article 36(2)(a) of the TAR NC). This is linked to the grey box for compliance with the publication requirements. As evident in Figure 43, only the TSOs from the MSs listed in the grey box will be able to submit to ENTSOG the information on their compliance with the requirement to publish the set of tariff information before the tariff period, as for the other cases the start of the tariff period is beyond the deadline of 31 December 2017.

White box: As explained at the beginning of this Chapter, the end of December 2017 is the estimated start date for preparing the final consultation document, to comply with the deadline established by the TAR NC (Article 26(1) of the TAR NC).

1) See Part 1, Chapter VIII 'Publication Requirements', 'When to Publish', 'Article 31 – Publication Notice Period'

What needs to be done as from AD 1:

In a number of instances, the TAR NC does not set out the start date for undertaking some activities to comply with an obligation, but only the deadline for complying with such an obligation. It appears to be reasonable to have an early start for undertaking the related activities, to ensure sufficient time for compliance:

- First of all, the definitions set out in Article 3 of the TAR NC need to be implemented. Not only the 'new' concepts, if relevant, need to be introduced but also the 'old' concepts which are already in use before the TAR NC entry into force need to be changed. For example, a change is necessary if at a national level a certain notion is used with a different meaning than attributed to it by the TAR NC, or if the meaning of a notion is labelled differently than by the TAR NC.
- As Article 4 of the TAR NC falls within the Chapter applicable as of AD 1, it would be necessary to start changing the way transmission and non-transmission services are delineated and the way the associated revenues are recovered. Article 4 covers all possible TSO tariffs: (1) split between transmission and non-transmission services according to paragraph 1; (2) setting transmission tariffs to take account conditions for firm capacity products under paragraph 2; (3) use of capacity-based transmission tariffs as a default under paragraph 3; (4) the criteria for commodity-based transmission tariffs and for non-transmission tariffs pursuant to paragraphs 3 and 4. However, Article 26 on periodic consultation and the associated Article 27(4) on NRA decision-making covers all such tariffs set out in Article 4. Therefore, although the AD for Article 4 is AD 1, the compliance date is AD 3.
- As explained at the beginning of this Chapter, the TAR NC envisages an option of conducting a/some 'intermediate' consultations under Article 26(1) as from AD 1. Time would be needed for the preparation of the respective consultation documents.
- As from AD 1, the TSOs may need to negotiate and agree on the attribution of the auction premium from the sales of bundled capacity (Article 21 of the TAR NC). The TAR NC is silent as to the exact deadline for entering into such an agreement, and only sets out the deadline for NRA approval, namely three months in advance of the annual yearly capacity auction. In absence of such approval, the 50/50 split applies. If the TSOs' agreement was previously approved by the NRAs before the TAR NC entered into force, no additional approval is needed as the deadline of *'no later than three months before the start of the annual yearly capacity auctions'* is met.
- As from AD 1, it is possible for entities operating interconnectors to prepare detailed reasoning (supporting documents and, where appropriate, a CBA) for their request for NRAs to grant a derogation from the application of some/all TAR NC Articles. Following the process established by Article 37 of the TAR NC, after that, NRAs will need time to assess and decide upon such requests.

What is advised to be done as from AD 1:

The obligations below do not include a specific start date, and a reasonable approach is therefore to start working on their compliance as from AD 1:

- For ACER's report on methodologies and parameters to determine the allowed/target revenue of TSO, NRAs need to clarify with ACER as from AD 1 the required information they need to send to ACER (Article 34(2) of the TAR NC). Since the time for ACER's preparation of the report on such methodologies and parameters is only 2 years after the TAR NC's entry into force, ACER would reasonably expect the information from NRAs as early as possible.
- The same 'early' assumption applies to ACER's work on a report on the application of the RPM under Article 36(5) of the TAR NC. An early start of such work is advisable to provide the description of the full range of the applied RPMs throughout the EU.

What is advised to be done before AD 1:

To comply with the obligations applicable as of AD 1 or shortly afterwards, it appears necessary to start undertaking some activities even before AD 1, in particular:

- Analyse and update national legislative and regulatory frameworks, which need to be changed to implement the TAR NC.
- Assess the impact on IT systems, which need to be changed to implement the TAR NC.
- Start changing the applied definitions and introduce the new definitions, if applicable.
- Prepare internally to conduct formal consultations, including early engagement with stakeholders.
- Start working on 'intermediate', if applicable, and final consultation documents: develop the CWD counterfactual, develop a chosen RPM, determine input parameters for both methodologies, develop a capacity forecast, perform the respective calculations per chosen RPM and the CWD counterfactual, perform the respective calculations per CAA, discuss internally and with NRA (if a TSO is responsible for conducting the consultation), translate in English to the extent possible.
- ACER's work on a template for the consultation document per Article 26(1) also appears to be a challenging task to be completed by 5 July 2017 – starting working earlier is advisable.

CALENDAR YEAR 2018

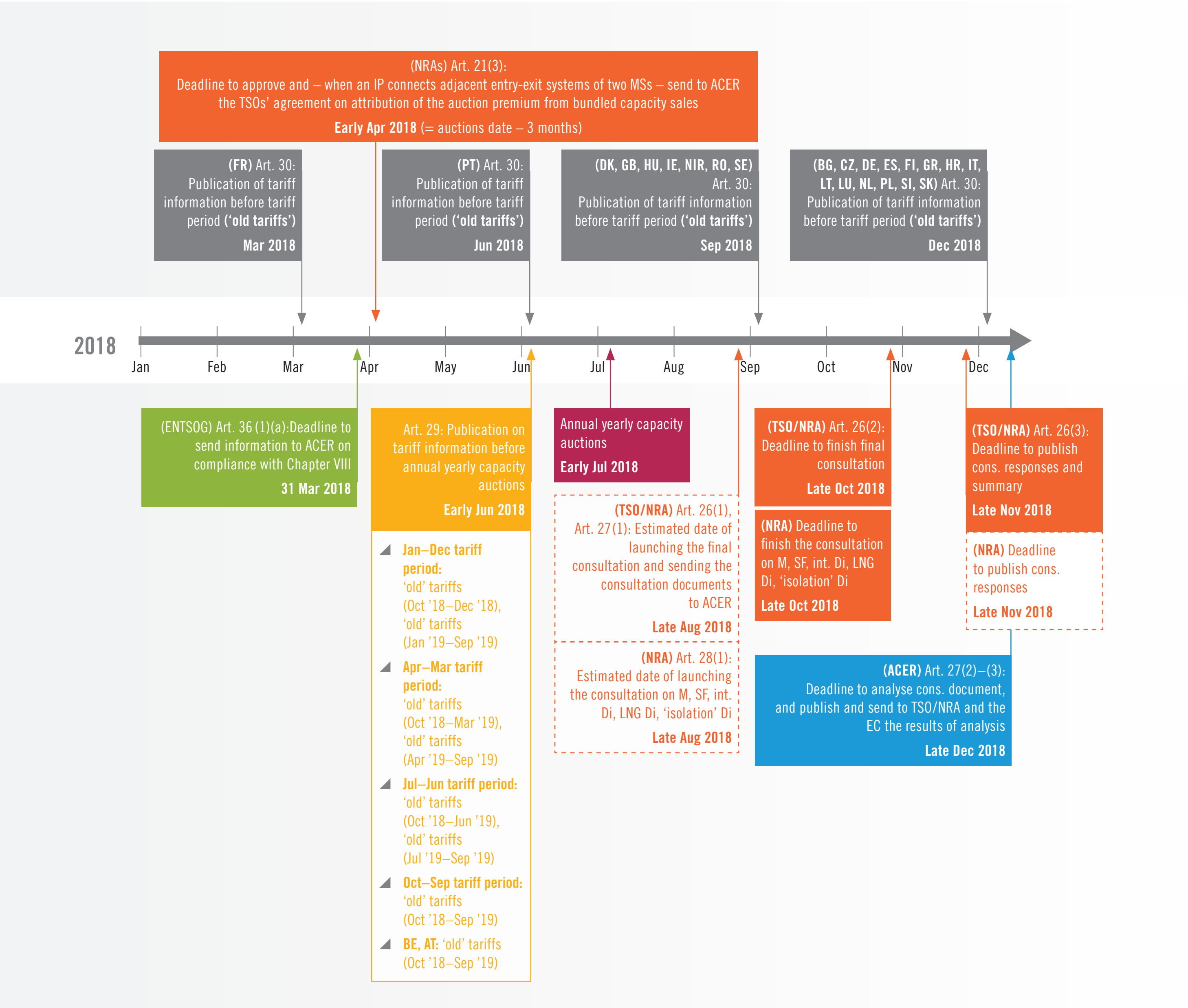


Figure 44: General timeline for 2018

Orange and white boxes: The orange box above the timeline is linked to the TSO agreements on the attribution of the auction premium from bundled capacity sales, mentioned under 'What needs to be done as from AD 1' in 'Calendar year 2017' above. As the first auction after the AD 1 will take place in July 2018, as envisaged by the CAM NC, early April 2018 for NRA approval of such agreement would allow 3 months' notice. This action is marked only once on the timeline, as it is assumed not to be an annual activity unless changes to such agreements require new NRA approvals and communication with ACER. When a given IP connects adjacent entry-exit systems of two MSs, such agreements need to be sent by NRAs to ACER for information.

As explained at the beginning of this Chapter, at least eight months are estimated as necessary for completion of the preparation of the final consultation document. The end of December 2017 indicated as the start date on the timeline 'Calendar year 2017' + eight months ends at the end of August 2018, which explains the estimated date for launching the final consultation under Article 26(1) of the TAR NC. Around such date, the consultation document(s) need to be forwarded to ACER for analysis. The TAR NC sets out that the minimum duration of the final consultation is two months which bring us to the end of October 2018. Within one month as from the end of the final consultation, it is necessary to publish the consultation responses received as well as their summary, and, to the extent possible, its translation in English, which is indicated as the end of November 2018.

In parallel with the final consultation under Article 26(1), the NRA must conduct another consultation on multipliers, seasonal factors, interruptible discounts, discounts at entry-points-from LNG facilities and discounts at entry-points-from/exit-points-to infrastructure ending isolation of MSs in respect of their gas transmission systems. The white box indicates the date of launching such consultation, just under the box indicating the date for launching the final periodic consultation: the end of August 2018. As the TAR NC foresees that both consultations must be 'conducted' at the same time, the end date of consultation under Article 28 coincides with the end of the final consultation under Article 26: the end of October 2018 as indicated by the orange boxes. In absence of explicit provisions in the TAR NC, ENTSOG assumed that the consultation responses for consultation under Article 28 should be published simultaneously with the responses to the final consultation under Article 26.

Blue box: The blue box is linked to the orange and white boxes on the final consultation. The TAR NC foresees that ACER has two months to analyse the final consultation document and publish the results of its analysis – as well as sending it to TSO/NRA and the EC – after the completion of the final consultation. On the assumption that those are sent simultaneously with the launch of the final consultation at the end of August 2018, ACER would have 4 months to complete its task by the end of December 2018.

Grey boxes: Similar to the grey box on the timeline 'Calendar year 2017', the four grey boxes on this timeline represent the deadlines for publication of the set of tariff information before the tariff period, for four tariff periods which is equal to one year: March, June, September and December 2018. Similar to the case explained for the 'old' tariffs published in December 2017, for this calendar year the tariffs will also be derived following the 'old' RPM. The same rule for publication of tariff information on ENTSOG's TP applies.

Red box: This box represents the date of the annual yearly capacity auctions per CAM NC.

Yellow box: This is the first time when the requirement to publish the set of tariff information before the annual yearly capacity auctions, on TSO/NRA website, takes place (Article 29 of the TAR NC). As explained in Part 1, Chapter VIII 'Publication requirements', such an obligation applies to all cases, regardless of the tariff period used. Furthermore, if the tariff period does not coincide with the gas year, it is necessary to publish separate reserve prices applicable for the respective time portions of the tariff periods falling within the gas year. The box under the yellow box lists such separate reserve prices. ENTSOG's TP will simultaneously provide a link to such information, and will also publish the reserve prices for firm/interruptible standard capacity products directly in a standardised table.

Green box: This box is linked to the green box on the timeline 'Calendar year 2017'. As explained above, ENTSOG's report to ACER on TSOs' compliance with the TAR NC Chapter VIII 'Publication requirements' will cover only the compliance of the TSOs functioning under the tariff period January–December with the obligation to publish the set of tariff information before the tariff period.

CALENDAR YEAR 2019

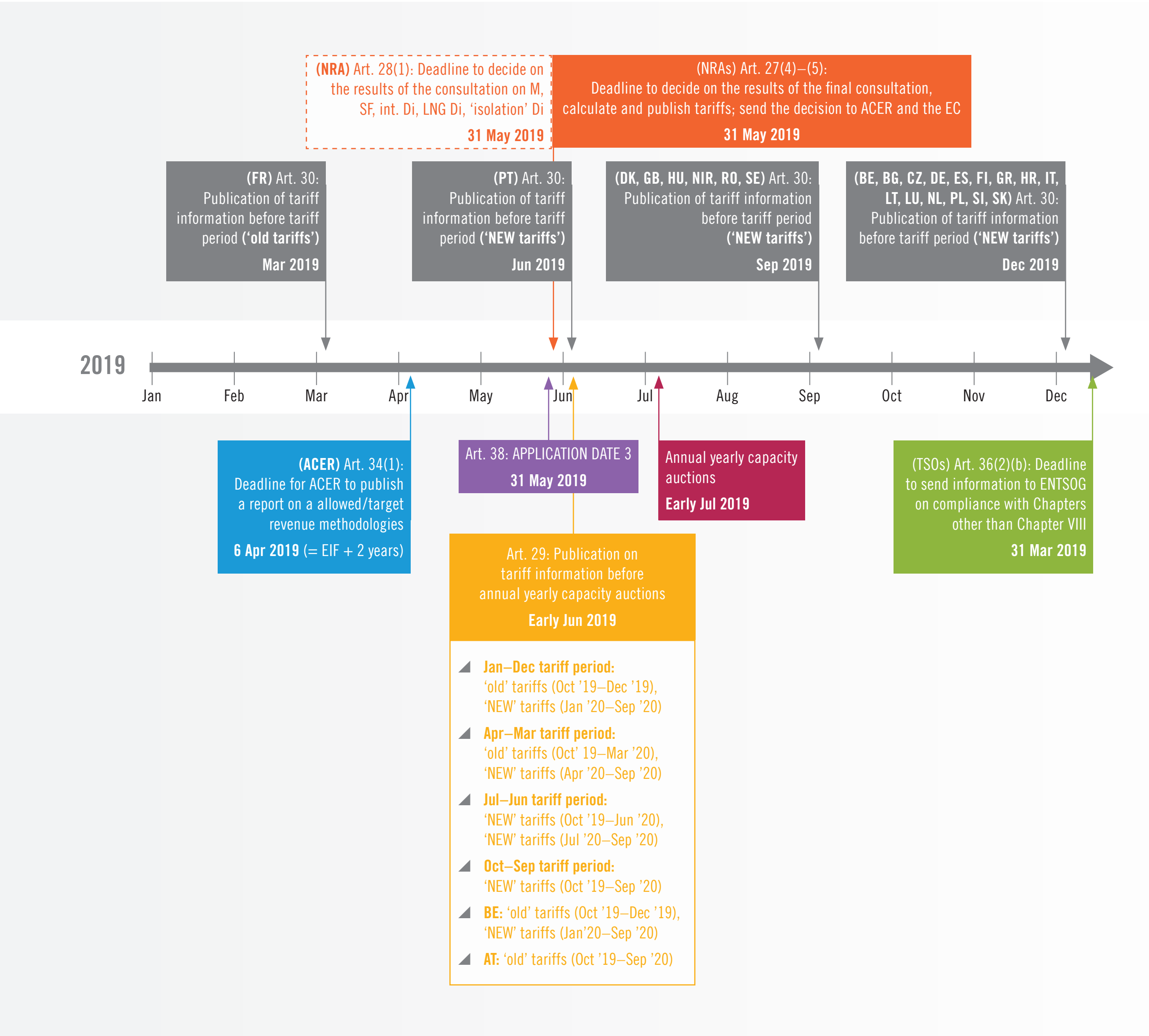


Figure 45: General timeline for 2019

Purple box: The purple box represents the last AD of the TAR NC ('AD 3'), 31 May 2019, for the following 3 Chapters: Chapter II 'Reference price methodologies', Chapter III 'Reserve prices' and Chapter IV 'Reconciliation of revenue'.

Orange and white boxes: The orange box is the deadline envisaged by the TAR NC as a result of the final periodic consultation. This is when the NRA needs to decide on all the issues identified in the final consultation document per Article 26(1) of the TAR NC, and must calculate and publish the tariffs in accordance with its decision. The NRA must send its decision to ACER and the EC.

Figure 45 shows that the deadlines for NRA decisions under Article 27(4) and 28(1) are linked to the deadline of 31 May 2019. However, the NRA decision on RPM should be taken in a timely manner before 31 May 2019 to allow for the completion of tariff calculations by 31 May 2019. Figure 45 indicates that these actions are simultaneous, as they appear in the same box, but in practice the NRA must take a decision before the completion of tariff calculations. Similarly, although Figure 45 shows that the NRA decision on multipliers, seasonal factors and various discounts mentioned above, per ENTSOG's assumption, takes place simultaneously with NRA decision under Article 27(4), it should occur well before 31 May 2019 to allow for the completion of tariff calculations by 31 May 2019.

Blue box: The deadline for ACER to publish a report on the allowed/target revenue methodologies is calculated as two years as from the TAR NC's entry into force, indicated by the blue box as 6 April 2019.

Grey boxes: Similar to the grey boxes on the previous two timelines 'Calendar year 2017 and 2018', the four grey boxes on this timeline indicate the deadlines for publishing the set of tariff information before the tariff period. In this year there will be 'new' tariffs following the 'new' RPM for the three tariff periods July–June, October–September and January–December. The same rule applies for publishing tariff information on ENTSOG's TP.

Red box: This box indicates the date of the annual yearly capacity auctions per CAM NC.

Yellow box: Similar to the timeline 'Calendar year 2018', the yellow box indicates the obligation to publish the set of tariff information before the annual yearly capacity auctions, on TSO/NRA website (Article 29 of the TAR NC). The box under the yellow box indicates which reserve prices are derived following the 'old' or 'new' RPM. The same rule for publication of tariff information on ENTSOG's TP applies.

Green box: This box represents the TAR NC obligation for TSOs to submit to ENTSOG the information on their compliance with Chapters other than Chapter VIII 'Publication requirements' by 31 December 2019 (Article 36(2)(b) of the TAR NC).

CALENDAR YEAR 2020

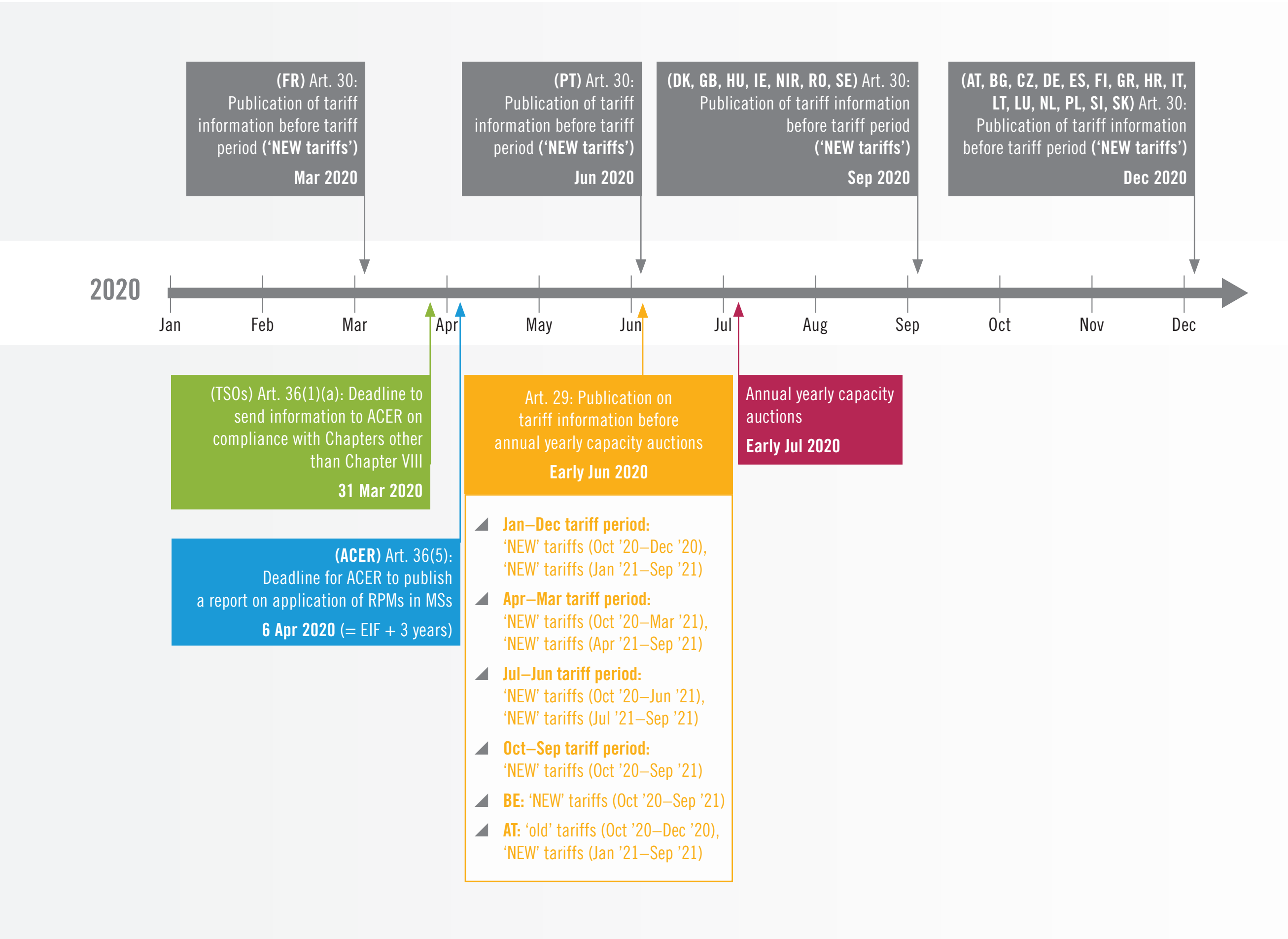


Figure 46: General timeline for 2020

Blue box: The deadline for ACER to publish a report on application of RPMs in MSs is calculated as three years as from the TAR NC's entry into force, indicated by the blue box as 6 April 2020.

Grey boxes: Similar to the grey boxes on the previous three timelines 'Calendar year 2017, 2018 and 2019', the four grey boxes on this timeline represent the deadlines for publication of the set of tariff information before the tariff period. In this year, for all the tariff periods, these are the 'new' tariffs following the 'new' RPM. The same rule for publication of tariff information on ENTSOG's TP applies.

Red box: This box represents the date of the annual yearly capacity auctions per CAM NC.

Yellow box: Similar to the previous two timeline 'Calendar year 2018 and 2019', the yellow box represents the obligation to publish the set of tariff information before the annual yearly capacity auctions, on TSO/NRA website (Article 29 of the TAR NC). The same rule on reserve prices derived following the 'old' or 'new' RPM applies (in 2020, only in Austria these will be not fully 'new' tariffs published before the annual yearly capacity auctions). The same rule applies for publishing tariff information on ENTSOG's TP.

Green box: This box is linked to the green box on the timeline 'Calendar year 2018', and indicates ENTSOG's report to ACER on TSOs' compliance with the TAR NC Chapters other than Chapter VIII 'Publication requirements'.

CALENDAR YEAR 2021

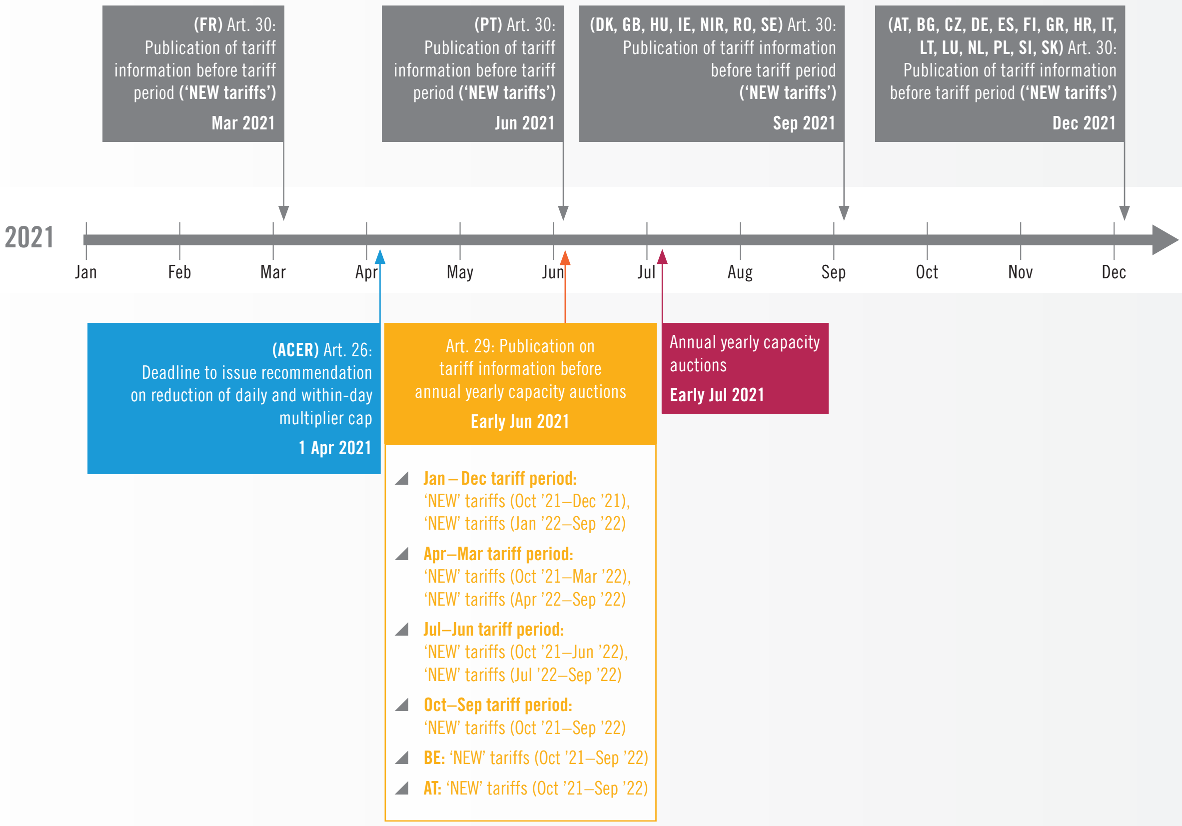


Figure 47: General timeline for 2021

Grey boxes: Similar to the grey boxes on all the previous three timelines, the four grey boxes on this timeline represent the deadlines for publication of the set of tariff information before the tariff period. The same rule applies for publishing tariff information on ENTSOG's TP.

Red box: This box represents the date of the annual yearly capacity auctions per CAM NC.

Yellow box: Similar to the previous three timelines 'Calendar year 2018, 2019 and 2020', the yellow box represents the obligation to publish the set of tariff information before the annual yearly capacity auctions, on TSO/NRA website (Article 29 of the TAR NC). This is the first time when the reserve prices for all the cases of different tariff periods will be derived following the 'new' RPM. In 2021 in all MSs there will be no 'old' tariffs published before the annual yearly capacity auctions. The same rule applies for publishing tariff information on ENTSOG's TP.

MULTI-TSO ENTRY-EXIT SYSTEMS WITHIN A MEMBER STATE

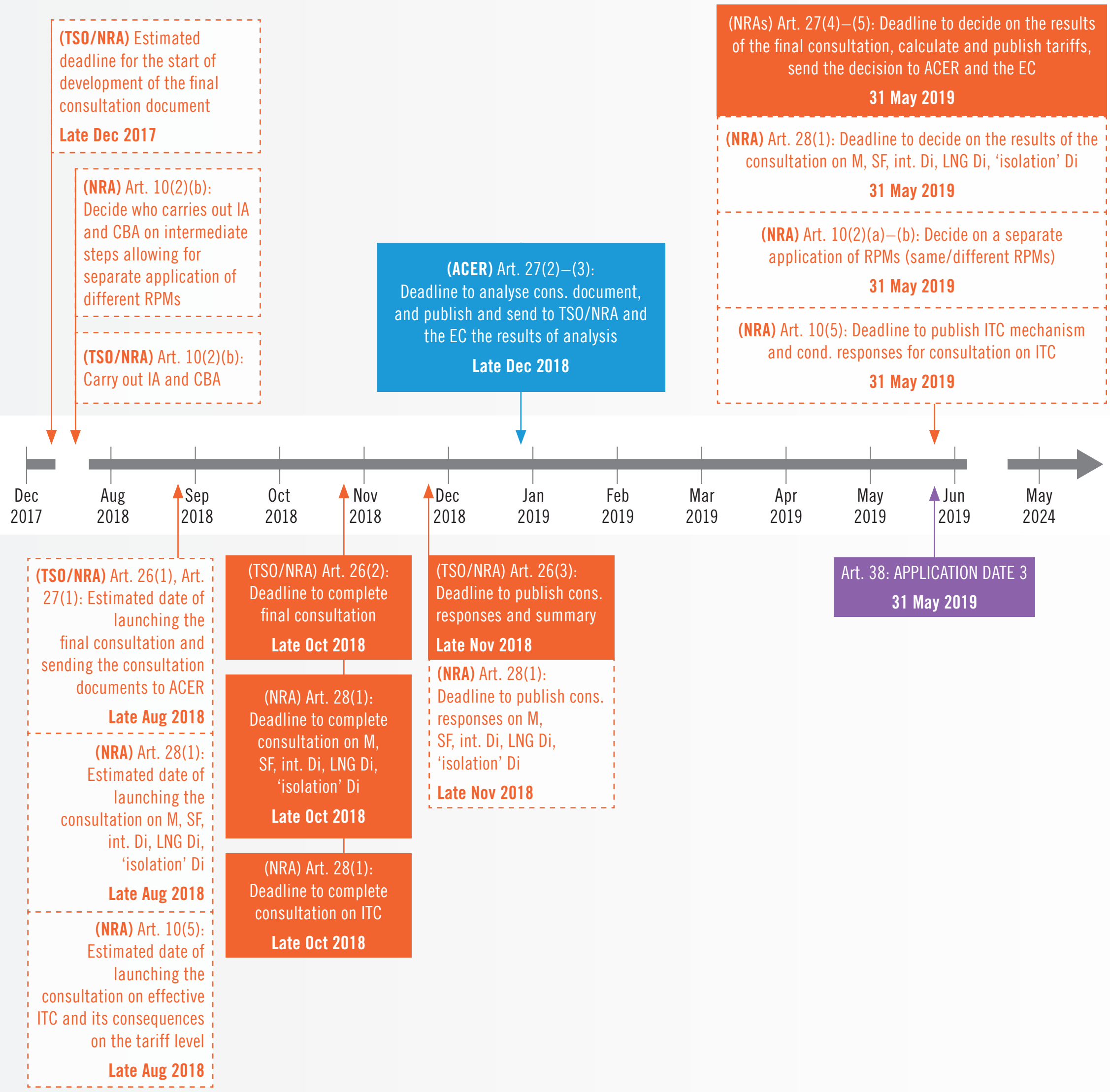


Figure 48: Timeline for multi-TSO arrangements within a MS

As explained above, certain obligations from Table 16 'Who is doing what' are not represented on the calendar year timelines above due to their specificity. These obligations are limited to multi-TSO entry-exit systems within a MS and appear in Figure 48.

Figure 48 shows only the process associated with the final consultation under Article 26, but with additional requirements for multi-TSO entry-exit systems within a MS. Therefore, most of the white and orange boxes are exactly the same as for the timeline above, except for those linked to Article 10 of the TAR NC. Other boxes on the timelines also apply to multi-TSO entry-exit systems within a MS, such as different ADs of the TAR NC, publication requirements before the tariff period and before the annual yearly capacity auctions, deadlines for ACER's reports, deadlines for information provision from TSOs to ENTSOG and for ENTSOG's implementation and effect monitoring reports.

The timeline in Figure 48 starts with December 2017 as the estimated deadline for the start of the development of the final consultation document, which is the same as for the timelines. August 2018 is the estimated date for launching the final consultation. The timeline then continues until 31 May 2019, which is the deadline for NRA decision-making after final consultation. May 2024 is the estimated deadline for the duration of separate application of RPM(s) in multi-TSO entry-exit systems within a MS.

In the absence of specific guidance from the TAR NC, Figure 48 allocates the NRA decision to the time period between December 2017 and August 2018 concerning who must carry out an impact assessment and a CBA on intermediate steps allowing for separate application of different RPM in case of entry-exit systems merger.

The TAR NC foresees that the consultation on effective ITC and its consequences for the tariff level (both for the case of joint and separate application of RPM(s) in multi-TSO entry-exit systems within a MS) is conducted simultaneously with the final consultation under Article 26 and consultation under Article 28. Thus, the three consultations will be launched and finished simultaneously. Also, the TAR NC envisages the publication of the responses to the Article 26 consultation within one month following the end of the consultation, and that by 31 May 2019 the NRA must take a decision on the applied RPM, and must calculate and publish 'new' tariffs. However, the TAR NC is silent as to the time for the NRA to publish the responses for consultation per Article 10(5) and the associated NRA decision-making, except for them to take place at the same time. Per ENTSOG's assumption, these will take place at the same time as NRA decisions for consultations under Article 26 and 28. As explained in 'Calendar Year 2019', these decisions should be taken in a timely manner before 31 May 2019 to allow for tariff calculations on the basis of such decisions. For multi-TSO entry-exit systems, more time may be needed for the calculation of tariffs, for example due to the necessity of an ITC mechanism.

Chapter III: Timelines for the TAR NC Implementation Depending on the Applied Tariff Period

Compared to the general timeline described in Chapter II, which applies throughout the EU, this Chapter deals with timelines customised per applied tariff period[1)]. The first four Figures cover the cases where the tariff period is equal to one year: January–December (BG, CZ, DE, ES, FI, GR, HR, HU[2)], IT, LT, LU, NL, PL, SI, SK), April–March (FR), July–June (PT) and October–September (DK, GB, NIR, IE, RO, SE). The last two Figures cover the cases where the tariff period is more than one year: the 5th timeline covers the situation in BE and the 6th – situation in AT.

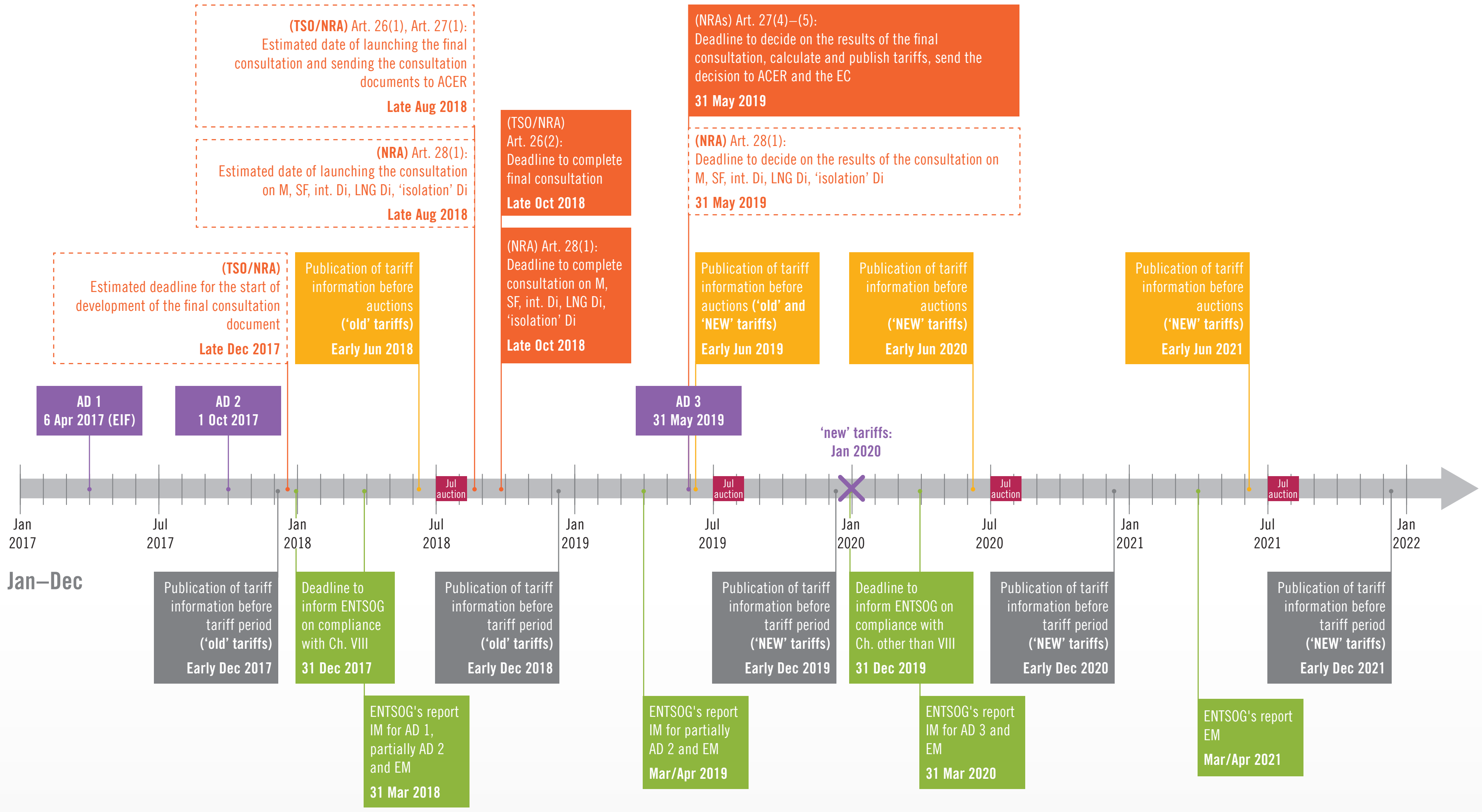
Each Figure includes the following boxes shown on the general timeline in Chapter II: different ADs of the TAR NC, annual yearly capacity auctions in July, publication of tariff information before the annual yearly capacity auctions and before the tariff period, deadlines for information provision from TSOs to ENTSOG. As with the general timeline in Chapter II, for publication requirements each box includes information on whether the respective tariffs are derived in accordance with the 'new' or 'old' RPM. In addition, each Figure shows the timing for ENTSOG's preparation of implementation and effect monitoring reports, which does not appear on the general timeline in Chapter II but rather on the respective timeline in Part 1.

Also, each Figure includes certain boxes from the general timeline in Chapter II which are deemed useful as a reminder of the timing for the final consultation under Article 26 and consultation under Article 28. These boxes capture the same timings as shown on the general timeline in Chapter II, and include the following: the start of the preparation of the final consultation document under Article 26, the launch and the finish of both consultations and the deadline for NRA decision-making for both consultations. Other boxes associated with the consultation requirements and deadlines for ACER's reports which are not shown on Figures below are exactly the same as for the general timeline in Chapter II.

1) See Part 1, Chapter I 'General provisions', Section 'Article 3(5) and 3(23) – regulatory period and tariff period'.

2) The tariff period applicable in Hungary will be changed to October–September as from 2017.

Figure 49: Customised timeline for January–December tariff period



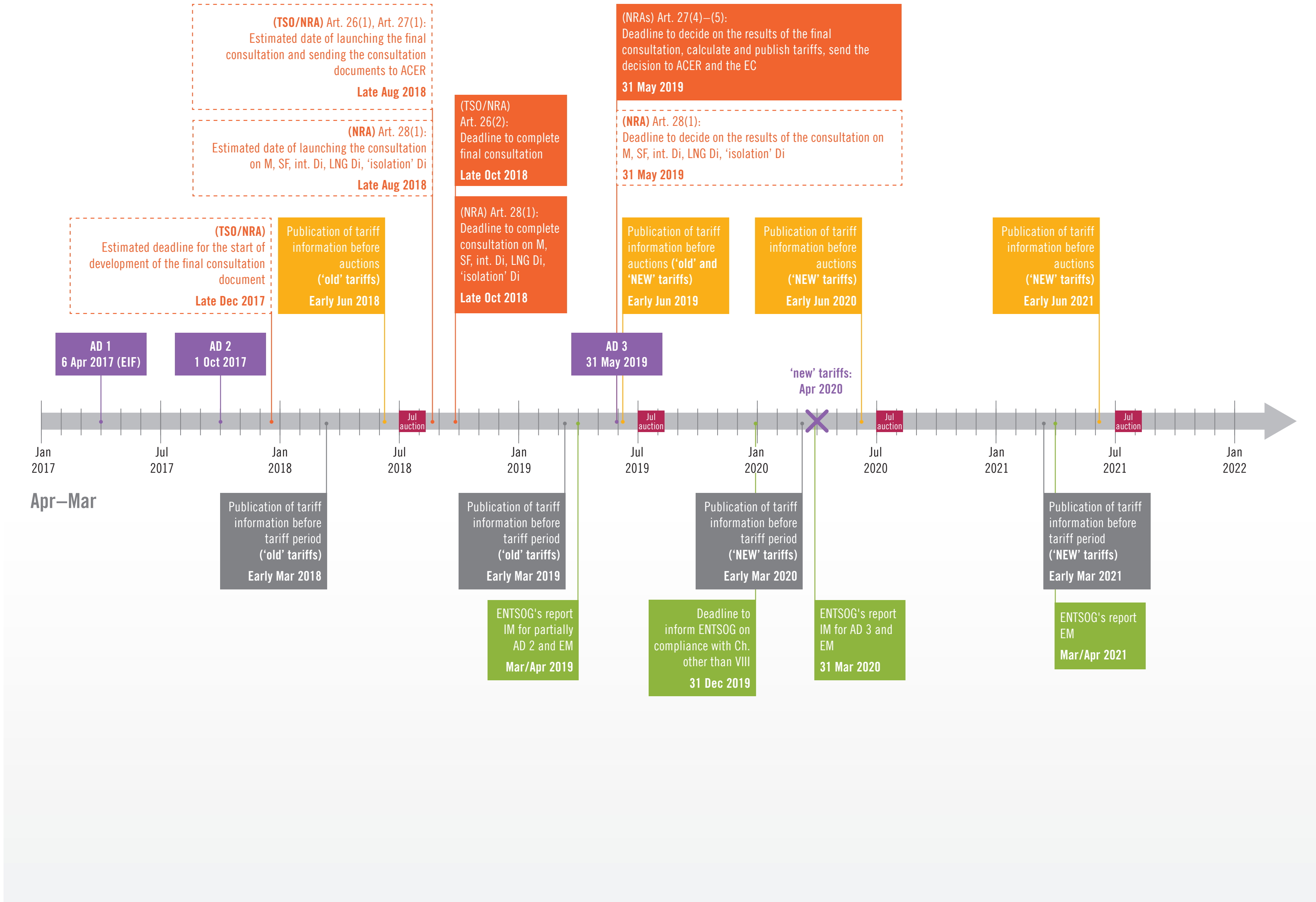
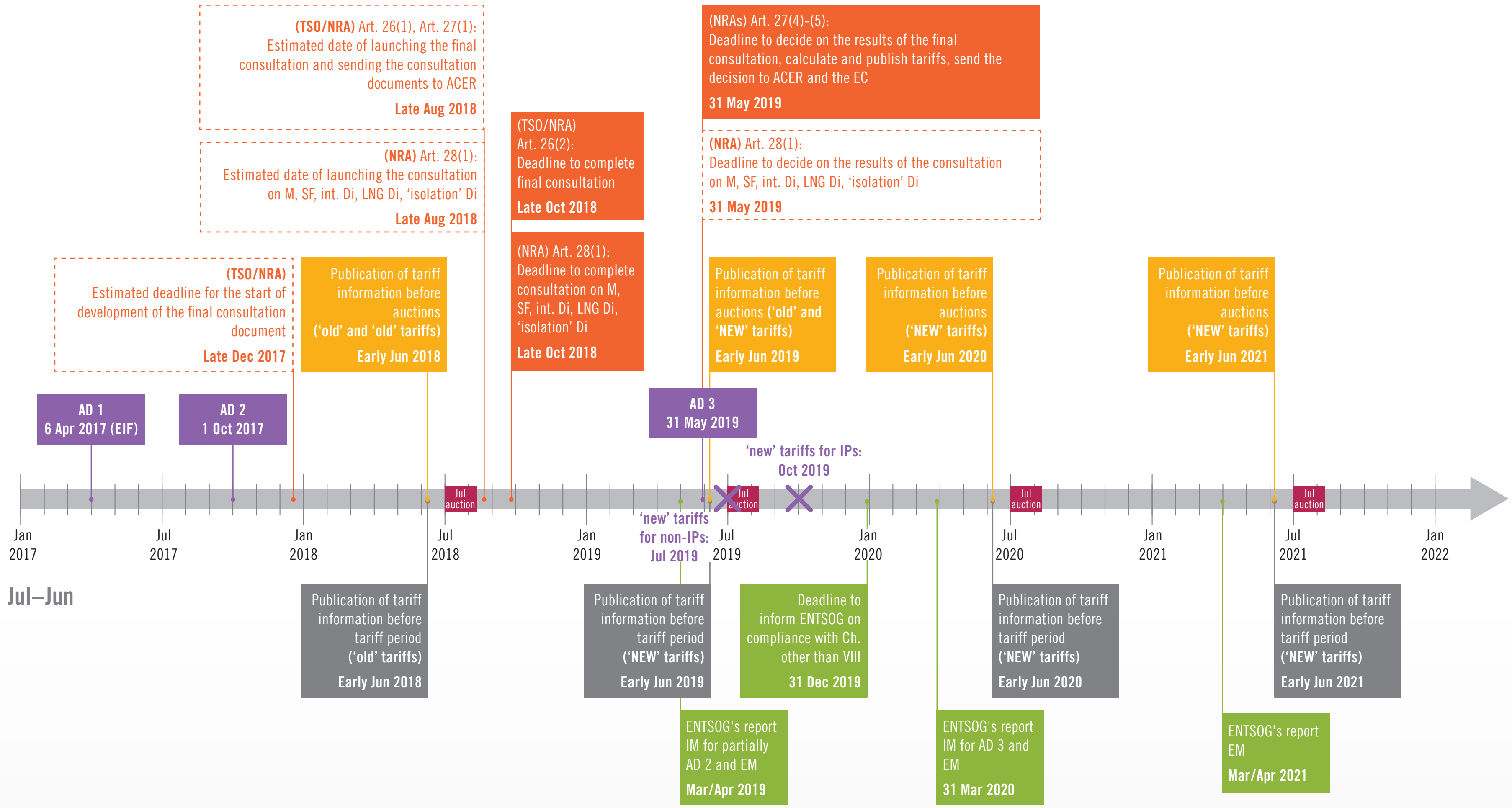


Figure 50: Customised timeline for April–March tariff period

Figure 51: Customised timeline for July–June tariff period



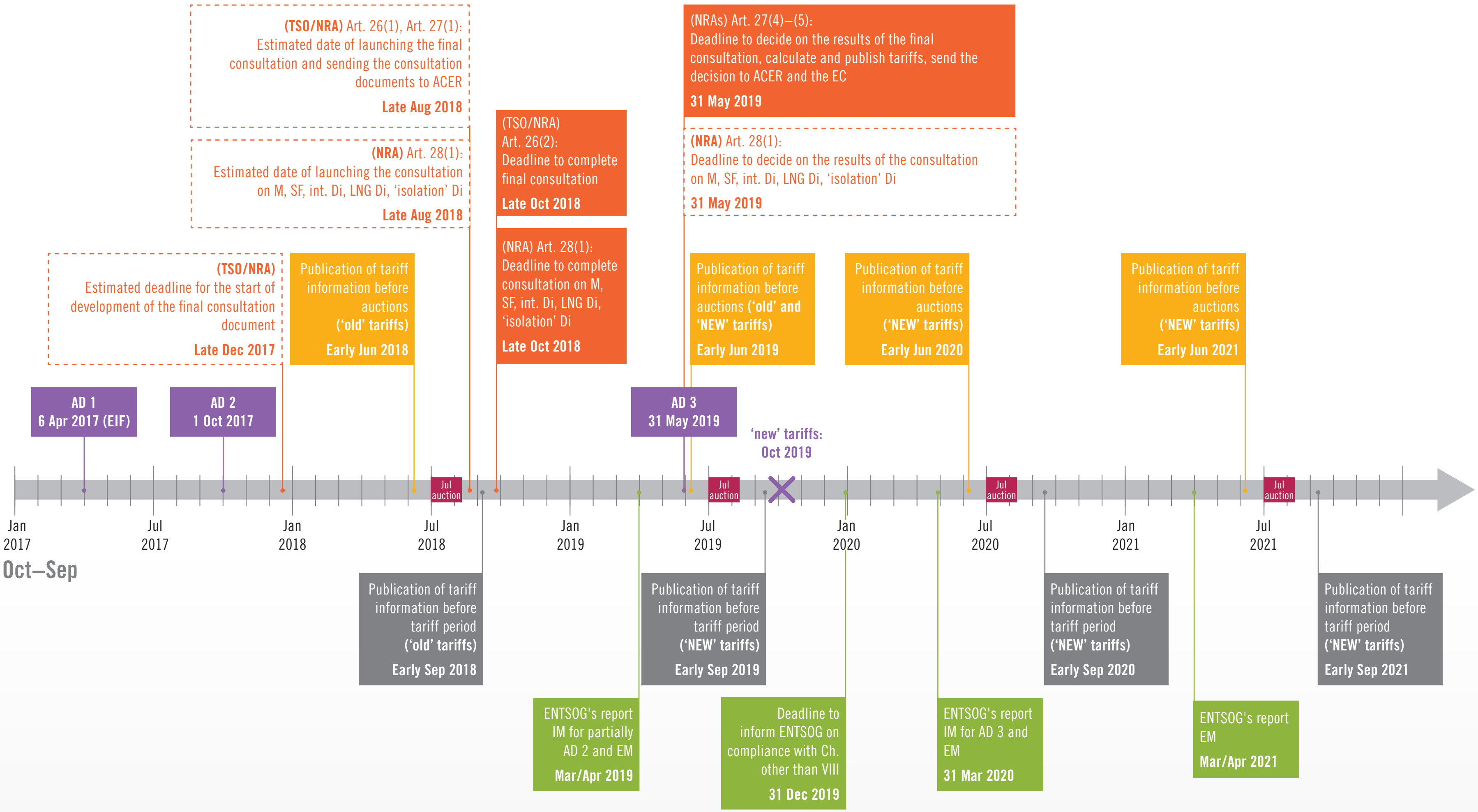


Figure 52: Customised timeline for October–September tariff period

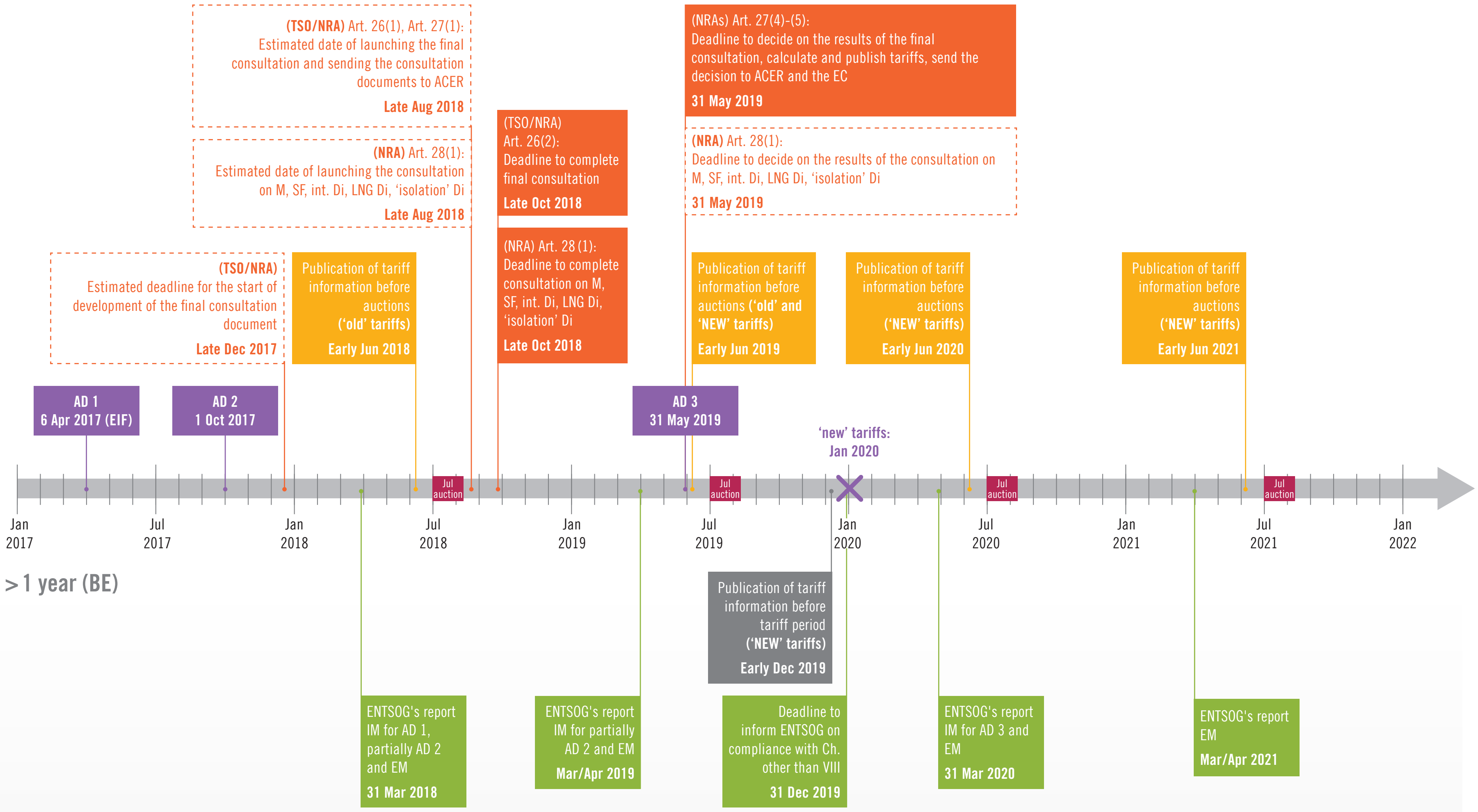


Figure 53: Customised timeline for tariff period longer than 1 year (BE)

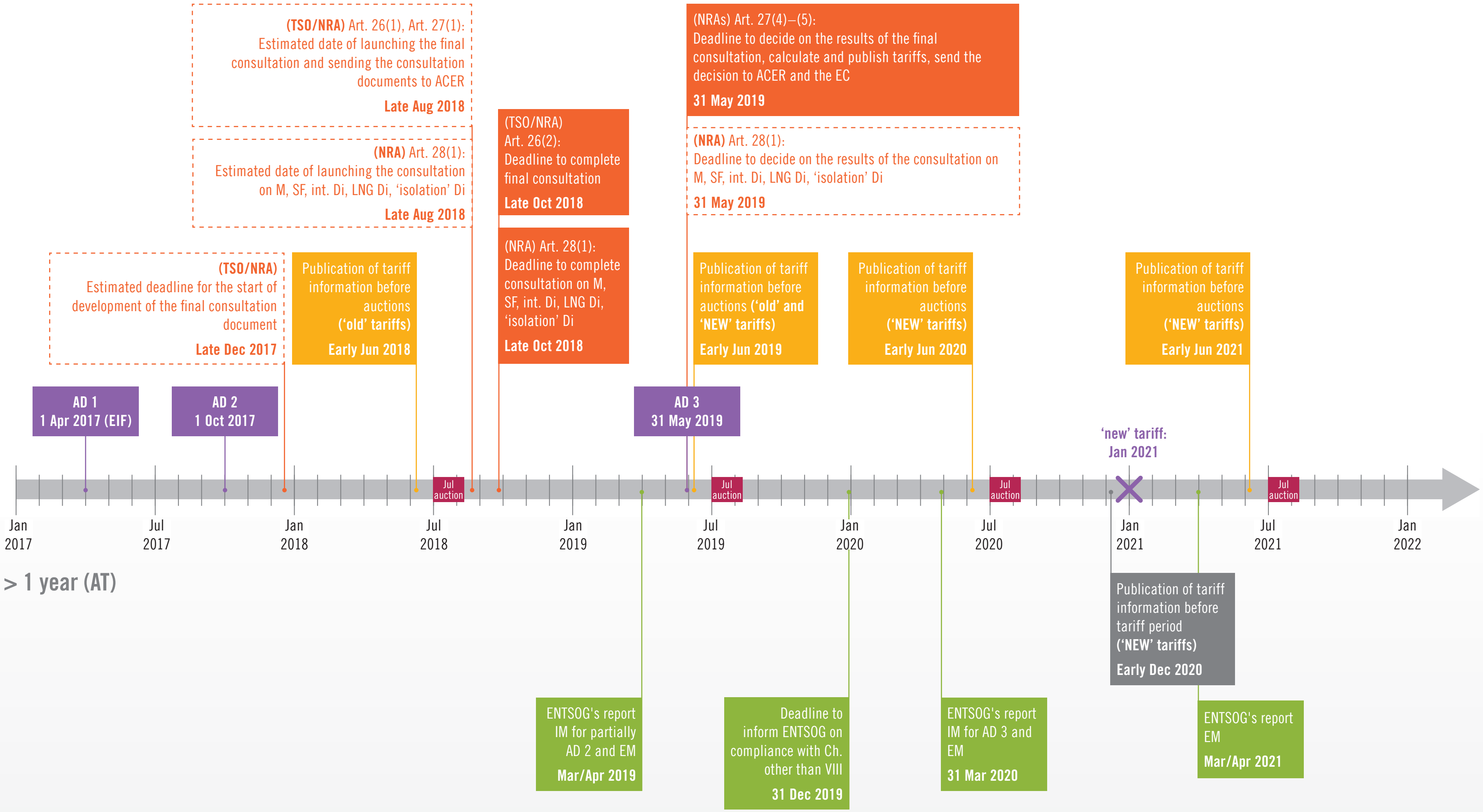


Figure 54: Customised timeline for tariff period longer than 1 year (AT)

Annexes


Image courtesy of GAZ-SYSTEM

Annex A

Articles 3(19) and 6(4)(b) – Example of Clustering and Equalisation

Entry-exit system with two entry points (IP) and three exit points to consumption (C).
Objective: Equalisation applied to the consumption points.

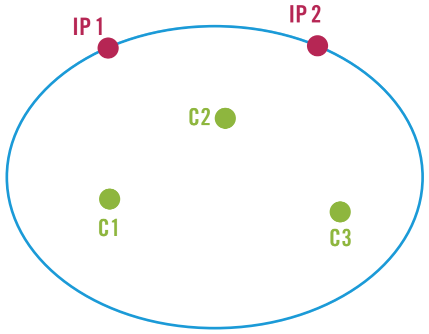


Figure 55: A simplified network

Clustering

Representation of one unique consumption cluster, or virtual consumption point (VCP), e.g. by using the longitude, the latitude and the capacity of each consumption point.

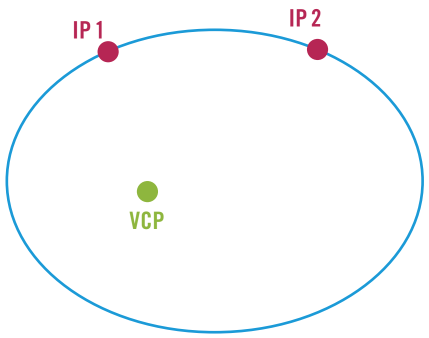


Figure 56: A simplified network with clusters

	lat	long	Capacity Entry	Capacity Exit
C1	48,79	2,14	0	15
C2	48,83	2,25	0	10
C3	48,78	2,45	0	5
VCP	48,80	2,28		

Table 17: Clustering points

As explained in Part 1 'Overview of the TAR NC requirements', Chapter I 'General provisions', Section 'Article 8(1)(c) – distance calculation', the calculation of the shortest pipeline distance can be determined by: (1) selecting a focal point within the grid representing the cluster; or (2) calculating the weighted average distance of all physical points combined in the cluster. The tariff at VCP may be calculated by taking this cluster as one exit point following either of these two approaches. Applying the RPM will calculate one single exit tariff to each of all three consumption points.

Equalisation

At first, the distances between each entry and exit point of the system were determined. Those distances and the given capacity are the inputs to apply the RPM if such RPM employs distance as a cost driver. Illustrative tariffs resulting from an RPM could be:

	Exit tariffs
C1	4
C2	2
C3	5

Table 18: Illustrative tariffs

The ex-post equalisation consists of calculating tariffs e.g. by using a capacity-weighted average approach per following formula:

$$\bar{T} = \frac{\sum T_n \times C_n}{\sum C_n}$$

Where:

$\bar{T}$ is the tariff of the equalised points

T_n is the tariff of a point

C_n is the capacity of a point

The calculated tariffs would be applied to any consumption point.

	Exit tariffs	Capacity Exit
C1	4	15
C2	2	10
C3	5	5
VCP	3,5	

Table 19: Tariff for the cluster

Annex B

Article 4(2) – Examples of Currently Offered Firm Capacity Products with 'Conditions'

For further details, please refer to the national documents envisaging such products: Austria[1]; Belgium[2], Germany[3], Luxembourg[4], the Netherlands[5].

EXAMPLES OF FIRM CAPACITY PRODUCTS WITH 'CONDITIONS'		
Firm capacity product with 'conditions'	**Explanation**	**TSOs offering a given firm capacity product with 'conditions'**
Restrictedly usable firm	Capacity that ensures firm freely allocable network access within an entry-exit-system on a firm basis within certain gas flows, within certain temperature ranges and/or entry-exit-system load/demand; Access to the VTP included	Thyssengas, Fluxys TENP, GRTgaz Deutschland, GTG Nord, OGE (called 'bFZK' in Germany – used on entry points to control local distribution of incoming flows; called 'TAK' if used at network points to storage facilities) Creos
Restrictedly allocable firm	Restrictedly allocable capacity ensures the injection of gas on a firm basis at entry point(s) and the withdrawal of gas at explicitly dedicated exit point(s) and vice versa on a firm basis Can use this capacity with 'explicitly dedicated exit point(s)', but not in combination with other exit/entry points or VTP	bayernets, Fluxys TENP, OGE, GUD (called 'BZK' in Germany; if the distance between the entry and exit points is short, the product may be called 'Shorthaul') Fluxys Belgium (called 'Wheeling and OCUC – Operational Capacity Usages Commitments')[6] GTS[7]
Dynamically allocable firm	Dynamically allocable capacity ensures the injection of gas on a firm basis at entry point(s) and the withdrawal of gas at explicitly dedicated exit point(s) and vice versa on a firm basis Functions as interruptible capacity in combination with the VTP and all exit/entry point(s) other than 'explicitly dedicated exit points'	GASCADE, GRTgaz Deutschland, GCA, TAG, NEL, GTG Nord, Fluxys Deutschland, Lubmin-Brandov Gastransport, ONTRAS (called 'DZK' in Germany)

Table 17: Examples of firm capacity products with 'conditions'

1) Definition 55 of the Gas Market Code: https://www.e-control.at/documents/20903/-/-/afbc2c68-672a-4ff0-8da5-62c7315f177c#page=15.

2) Section 3.2, Attachment A: http://www.fluxys.com/belgium/en/Services/Transmission/Contract/~/media/Files/Services/Transmission/TermsConditions/Version20161020/ACT_EN_Approved_20161020.ashx

3) GasNZV § 3, Abs. 3: https://www.gesetze-im-internet.de/gasnzv_2010/BJNR126110010.html

4) http://www.creos-net.lu/fournisseurs/gaz-naturel/acces-capacites-transport.html, http://www.creos-net.lu/fournisseurs/gaz-naturel/capacites-ip-remich.html

5) Article 2.1.6 of the Transmission Code, description of shorthaul: https://www.gasunietransportservices.nl/en/shippers/terms-and-conditions/dutch-network-code

6) Wheeling is shorthaul over a zero distance (two flanges on the same physical location) to allow shippers a U-turn on the Dutch or Belgium border. 'OCUC' means an entry or exit service subject to an Operational Capacity Usage Commitment (OCUC), which is an operational agreement between network user and TSO in the framework of the proactive congestion management policy.

7) GTS offers a product called shorthaul on a FCFS basis. Shorthaul is different from restricted allocable firm capacity, as shorthaul gives access to exactly one physical exit point using flange capacity that exceeds the available technical capacity. Shorthaul does not limit the amount of available technical capacity on auction at any network point in the GTS transmission network. The feasibility of shorthaul depends on the distance between the entry and the exit point, the amount of capacity and the duration of the contract. These parameters determine the shorthaul tariff.

Annex C

Article 5 – Example of Cost Allocation Assessments

This Annex describes the case of a TSO applying the CAA on capacity-based and commodity-based transmission tariffs.

In the following sections, calculations are explained step by step based on a fictional TSO network. Tables with exemplary figures are added to provide for easier understanding.

Table A: Distances between Entries and Exits[1]

TABLE A: DISTANCES BETWEEN ENTRIES AND EXITS						
		Distance (km)				
		Exit				
		IP 1	IP 2	IP Exit 5	IP 3	Consumption
Entry	LNG	650	820	840	420	460
	IP 1	0	350	520	360	200
	IP Entry 4	150	480	660	430	270
	IP 2	350	0	230	430	270
	IP 3	360	430	440	0	170

Table 18: Distances between Entries and Exits

The first Table shows the distance from each exit point to each entry point of the system. While 'IP Exit 5' and the local consumption are just noted as exits, 'IP Entry 4' and the point 'LNG' are specified as entries only. All three other IPs function as an entry and exit point. The consumption in this model is representative for many exits and can be assimilated to a cluster. By building the weighted centre of those single consumption exits, all are summarized to this one location. The distances are then determined according to the approach chosen for CAA by the TSO or NRA (no mandatory approach in the TAR NC)[2].

Two parts are considered.

- **Part I** presents the CAA for the capacity-based transmission tariffs (all TSOs use such tariffs, therefore this CAA is mandatory for all TSOs).
- **Part II** presents the CAA for the commodity-based transmission tariffs (optional, only for TSOs which apply such tariffs).

1) Consumption refers to 'intra-system network use'. It is forecasted contracted capacity, as per Article 5 provisions.

2) For distance calculations between entry and exit points, one assumes here that the concept of 'flow scenario' referred to in Article 8 on the CWD counterfactual is also applied to the CAA. E. g. it is impossible to flow gas from IP 1 seen as an entry point to IP 1 seen as an exit point. Therefore, for the calculation of the average distance for exit point IP 1, it is necessary to remove the capacity value of entry point IP 1 from the denominator. If this adjustment is not made, average distances will be underestimated at entry (resp. exit) points where flow scenarios do not exist with at least some exit (resp. entry) points. However, for the CAA it is also possible to assume that the concept of flow scenario does not apply, since Article 5 on CAA does not make it a requirement.

CAA RELATING TO TRANSMISSION SERVICES REVENUE FROM CAPACITY-BASED TARIFFS

This Part considers the CAA on **capacity-based** transmission tariffs.

In this Part, one assumes that contracted capacity at exit IPs corresponds to 'cross-system network use' and contracted capacity at domestic consumption points corresponds to 'intra-system network use'.

Further, Cost Drivers in this Scenario are **a combination of distance and capacity**. For the expected revenues, the allowed total capacity revenue and a split of this into exit and entry share is given.

Table B: Average Distance to a specific exit (or entry)

TABLE B: AVERAGE DISTANCE TO A SPECIFIC EXIT (OR ENTRY)				
Average distance (km) for each exit point to the group of entry points				
IP 1	IP 2	IP Exit 5	IP 3	Consumption
345	509	543	408	282

Average distance (km) for each entry point		
	to intra exits	to cross exits
LNG	460	663
IP 1	200	436
IP Entry 4	270	460
IP 2	270	328
IP 3	170	413

Table 19: Average distance to a specific exit (or entry)

Taking into account the capacity and the distance of every entry of the system to one specific exit, a capacity weighted average distance can be calculated for this exit point. Capacities are shown in the following Table C. This average distance of one exit point is determined by the sum of each entry capacity, times the distance to this respective entry point from the considered exit point, divided by the sum of all entry capacities. An average distance for a specific exit point would be calculated as in the following equation.

$$\overline{Distance_{exit}} = \frac{\sum Distance\ to_{entry,i} \times Capacity_{entry,i}}{\sum Capacity_{entry,i}}$$

The calculation of average distances for each entry point to the group of exit points is carried on by analogue processing. In contrast to exit points, for entry points there is a distinction regarding the average distance to intra-system exit points and to cross-system exit points. The distance to intra system exit points is the actual distance to the exit point Consumption, while the distance to the cross-system exit points is again calculated with the formula above as the capacity weighted average between the cross-system exit points. This distinction is made to later define the intra/cross system drivers for entry points.

Table C: Cost Drivers and Entry Capacity Split

TABLE C: COST DRIVERS AND ENTRY CAPACITY SPLIT							
		Capacity (GWh/d)					
		Exit					
		IP 1	IP 2	IP Exit 5	IP 3	Consumption	Total
Entry	LNG						360
	IP 1						580
	IP Entry 4						580
	IP 2						500
	IP 3						40
	Total	150	60	260	220	3,000	
	Drivers for Exit Points	51,730	30,531	141,283	89,786	844,660	

Driver for each Entry (Intra-Use)	Driver for each Entry (Cross-Use)	Entry Cap (Intra-Use)	Entry Cap (Cross-Use)
110,132	79,951	239	121
77,146	84,688	386	194
104,147	89,393	386	194
89,782	55,001	333	167
4,522	5,536	27	13
	Totals:	1,370	690
			Acc. to Art 5(5)(a)

Table 20: Cost drivers and entry capacity split

Drivers in this Scenario are referred to as the product of Capacity and the average distance. For exit points it is the respective capacity at a point times the average distance to the entry points in this given system which is calculated as in the previous section.

$$\text{Driver}_{\text{exit,i}} = \overline{\text{Distance}}_{\text{exit}} \times \text{Capacity}_{\text{exit,i}}$$

The Drivers for each entry point are calculated by analogue processing. For entry points although, the Drivers will again be split and allocated to intra- and cross-system use. This is required for the assessment. These Drivers are determined by entry capacity and the relevant average distance to cross- and intra-system exits which was calculated in the previous paragraph. **Drivers for intra-use and cross-use are only considered for the CAA, not for tariff derivation**[1]. The entry capacity is also split and allocated to cross- or intra-system use. This split is made in accordance to Article 5(5)(a) and explained in the following paragraph.

1) Drivers for intra-use and cross-use are not used for tariff derivation because a TSO does not publish cross-use entry capacity tariffs, cross-use exit capacity tariffs, intra-use entry capacity tariffs or intra-use exit capacity tariffs. A TSO only publishes entry capacity tariffs and exit capacity tariffs, regardless of the intra- or cross-use of the capacity.

For performing the assessment, to determine the capacity revenues obtained by intra- or cross-system network use according to Article 5(5), the entry capacity itself must be allocated to intra- or cross-system use. **As set out in Article 5(5)(a), the entry capacity allocated to cross-system use must be equal to the actual total cross-system exit capacity.** Entry capacities allocated to cross-system use are therefore calculated as in the following formula. This guarantees that the total entry capacity for cross-system use equals the 690 of total cross-system exit capacity[1].

$$Entry\ Cap_{cross,i} = \frac{\sum Exit\ Cap_{cross,i}}{\sum Entry\ Cap_i} \times Entry\ Cap_i$$

Entry Capacity for cross-system use can therefore not be determined just by the share of cross-system exit capacity to total exit-capacity, but it must be as per Article 5(5)(a).

Only the rest of the capacities of each entry will then be allocated to intra-system use.

Table D: Capacity revenue, tariffs, allocation of revenues and conduction of test

In this table, the setting of a total of capacity revenue as well a targeted split in capacity revenues for exit and entry is introduced, with a 40/60 entry-exit split decided arbitrarily. Therefore entry and exit capacity revenues are determined. Entry and exit capacity tariffs are also arbitrarily set here, because **RPM derivation of tariffs is not part of this example on CAA.**

TABLE D: CAPACITY REVENUE. TARIFFS. ALLOCATION OF REVENUES AND CONDUCTION OF TEST						
		Exit tariffs				
Capacity revenue (€)	800,000	**IP 1**	**IP 2**	**IP Exit 5**	**IP 3**	**Consumption**
Entry share	40 %	98	147	220	147	122
Exit share	60 %					
Entry revenues	320,000				**Entry Tariffs**	
Exit revenues	480,000				**LNG**	265
Entry revenues dedicated for Intra	212,869	Acc. to Art 5(5)(c)			**IP 1**	106
Entry revenues dedicated for Cross	**107,131**	Acc. to Art 5(5)(b)			**IP Entry 4**	159
Exit revenues from Intra	366,000				**IP 2**	133
Exit revenues from Cross	113,060				**IP 3**	106
Revenue for Intra	578,869					
Revenue for Cross	220,191					**Test**
Cost driver for Entry Intra	**385,728**				**Ratio intra**	0.4705
Cost driver for Exit Intra	844,660				**Ratio cross**	0.3507
Cost driver for Intra	1,230,388				**CAA**	29.18 %
Cost driver for Entry Cross	**314,570**				**justification required**	
Cost driver for Exit Cross	313,330					
Cost driver for Cross	627,900					

Table 21: Capacity revenue, tariffs, allocation of revenues and conduction of test

1) In Table C, compare 690 as the total of the entry column in blue in the previous table, and the total of Exit columns IP 1, IP 2, IP Exit 5 and IP 3 (690 = 150 + 60 + 260 + 220).

The allocation of entry capacity revenues to cross-system use (blue fond) is made in accordance to Article 5(5)(b). It is the Sumproduct of the entry capacity tariffs and the entry capacities allocated to cross-system use (Table C, blue font). The rest of the entry capacity revenues are then allocated to intra-system use.

Exit capacity revenues are determined by the exit capacity and the exit tariffs. The tariff for the intra-system exit (consumption) times its respective exit capacity determines the exit capacity revenue from intra-system use. The rest of the exit capacity revenues are therefore coming from cross-system use.

The cost drivers for intra- and cross-system uses are determined by adding the drivers shown in Table C. Cost drivers for entry Intra is the addition of the Driver for each entry (Intra-Use) which were introduced in Table C. Cost driver for entry Cross is calculated analogously. Cost driver exit cross and intra are simply the addition of the drivers for the relevant exit points in Table C. Cost driver exit intra is the cost driver of the consumption point and cost driver exit cross the addition of the other four drivers for exit points.

The value of Cost driver for Intra is now the addition of the respective intra drivers for the entry and exit. Cost driver cross is the addition of the respective cross drivers for both entry and exit. These two parameters represent $Driver_{cap}^{intra}$ and $Driver_{cap}^{cross}$ from Article 5 in the TAR NC.

The amount of $Revenue_{cap}^{intra}$ which is stated in the TAR NC is the addition of both abovementioned capacity revenues for intra-system use. The parameter $Revenue_{cap}^{cross}$ is therefore the addition of both the exit and entry capacity revenues from cross-system use.

With those four parameters highlighted in green, the CAA can be performed as described in the TAR NC. The ratios for intra and cross can be calculated and the parameter $Comp_{cap}$ (CAA in the table above) can be tested to be above 10 %. The NRA has therefore to give justification regarding this value.

PART II CAA RELATING TO TRANSMISSION SERVICES REVENUE FROM COMMODITY-BASED TARIFFS

This Part considers the CAA on **commodity-based** transmission tariffs.

Compared to the previous Part on CAA for capacity-based transmission tariffs, one assumes now that the amount of gas flows at exit IPs corresponds to ‘cross-system network use’ and the amount of gas flows at domestic consumption points corresponds to ‘intra-system network use’.

Further, Cost Drivers in this Scenario are assumed to be a combination of distance and gas flows, which is consistent with Article 5(1)(b)(ii). For the expected revenues, the allowed total commodity revenue and a split of this into exit and entry commodity shares is given. Entry (resp. exit) commodity tariff is common to all entry (resp. exit) points in the system, as per Article 4(3)(a)(ii). Entry and exit commodity tariffs are set arbitrarily, with respective values being 3 €/GWh and 5 €/GWh.

In the following sections, calculations are explained step by step based on a fictional TSO network. Tables with exemplary figures are added to provide for easier understanding. Some assumptions are the same as the ones for the CAA for capacity tariffs (cf. above).

Table A: Distances between Entries and Exits[1]

TABLE A: DISTANCES BETWEEN ENTRIES AND EXITS						
		Distance (km)				
		Exit				
		IP 1	IP 2	IP Exit 5	IP 3	Consumption
Entry	LNG	650	820	840	420	460
	IP 1	0	350	520	360	200
	IP Entry 4	150	480	660	430	270
	IP 2	350	0	230	430	270
	IP 3	360	430	440	0	170

Table 22: Distances between Entries and Exits

The first Table shows the distance from each exit point to each entry point of the system. This is exactly the same matrix as for the previous capacity example for CAA[2].

Table B: Average Distance to a specific Exit (or Entry)

TABLE B: AVERAGE DISTANCE TO A SPECIFIC EXIT (OR ENTRY)				
Average distance (km) for each exit point to the group of entry points				
IP 1	IP 2	IP Exit 5	IP 3	Consumption
345	509	543	408	282

Average distance (km) for each entry point		
	to intra exits	to cross exits
LNG	460	739
IP 1	200	457
IP Entry 4	270	516
IP 2	270	291
IP 3	170	423

Table 23: Average distance to a specific Exit (or Entry)

Taking into account the flows and the distance of every entry of the system to one specific exit, a commodity weighted average distance can be calculated for this exit. Flows are shown in the following Table C. This average distance of one exit is determined by the sum of each entry flow, times the distance to this respective entry from the considered exit, divided by the sum of all entry flows. An average distance for a specific exit would be calculated as in the following equation.

$$\overline{Distance_{exit}} = \frac{\sum Distance\ to_{entry,i} \times Flow_{entry,i}}{\sum Flow_{entry,i}}$$

1) Consumption refers to 'intra-system network use', as per the comment at the start of Part II. It corresponds to the amount of gas flows, as per Article 5 provisions. One assumes here that this amount of gas flows is the forecast used for the RPM application (another assumption could have been to use past actual values).

2) For this commodity-based CAA, similarly to the capacity-based case, only entry and exit points connected via a flow scenario are considered here. The flow scenario assumption is not mandatory in Article 5 though.

The calculation of average distances for each entry point to the group of exit points is carried out by analogue processing. In contrast to exit points, for entry points there is a distinction regarding the average distance to intra-system exits and to cross-system exits. The distance to intra system exits is the actual distance to the exit point named 'Consumption', while the distance to the cross-system exits is again calculated with the formula above as the commodity weighted average between the cross-system exits. This distinction is made to later define the intra/cross system drivers for entry points.

Table C: Cost Drivers and Entry Commodity Split

TABLE C: COST DRIVERS AND ENTRY COMMODITY SPLIT

		Commodity (TWh)					
		Exit					
		IP 1	IP 2	IP Exit 5	IP 3	Consumption	Total
Entry	LNG						111.4
	IP 1						179.5
	IP Entry 4						179.5
	IP 2						154.8
	IP 3						12.4
	Total	13.8	14.4	47.3	14.7	547.5	
	Drivers for Exit Points	4,759	7,321	25,710	6,003	154,150	

Driver for each Entry (Intra-Use)	Driver for each Entry (Cross-Use)	Entry Comm (Intra-Use)	Entry Comm (Cross-Use)
44,013	11,654	95.68	15.76
30,830	11,612	154.15	25.40
41,621	13,100	154.15	25.40
35,880	6,364	132.89	21.90
1,807	742	10.63	1.75
	Totals:	547.50	90.21
			Acc. to Art 5(5)(a)

Table 24: Cost drivers and entry commodity split

Drivers in this Scenario are referred to as the product of Flows and the average distance. For exit points it is the respective flow at this point, times the average distance to the entry points in this given system which is calculated as in the previous section.

$$\mathrm{Driver}_{\mathrm{exit,i}} = \overline{\mathrm{Distance}_{\mathrm{exit}}} \times \mathrm{Flow}_{\mathrm{exit,i}}$$

The Drivers for each entry point are calculated by analogue processing. **Similar to capacity, drivers for commodity intra-use and cross-use are only considered for the CAA, not for tariff derivation**[1)]. The entry flow is also split and allocated to cross- or intra-system use. This split is made in accordance to Article 5(5)(a) and explained in the following paragraph.

1) As for the Capacity section, a TSO does not publish cross-use entry commodity tariffs, cross-use exit commodity tariffs, intra-use entry commodity tariffs or intra-use exit commodity tariffs. A TSO only publishes entry commodity tariffs and exit commodity tariffs, regardless of the intra- or cross-use of the flow.

For performing the assessment, to determine the commodity revenues obtained by intra- or cross-system network use according to Article 5(5), the entry flow itself must be allocated to intra- or cross-system use. As set out in Article 5(5)(a), the entry flow allocated to cross-system use must be equal to the actual total cross-system exit flow. Entry flow allocated to cross-system use is therefore calculated as in the following formula. This guarantees that the total entry flow for cross-system use equals the 90.21 TWh of total cross-system exit flow[1].

$$Entry\ Flow_{cross,i} = \frac{\sum Exit\ Flow_{cross,i}}{\sum Entry\ Flow_i} \times Entry\ Flow_i$$

Therefore, entry flows for cross-system use cannot be determined just by the share of cross-system exit flows to total exit capacity, but must be as per Article 5(5)(a).

Only the rest of the flows of each entry will then be allocated to intra-system use.

Table D: Commodity revenue, tariffs, allocation of revenues and conduction of test

In this table, the setting of a total of allowed commodity revenue as well as arbitrarily set values for entry and exit commodity revenue are introduced. Therefore entry and exit commodity revenues are determined. Entry and exit commodity tariffs are also arbitrarily set here, **because derivation of commodity tariffs is not part of this example on CAA for commodity-based tariffs**.

TABLE D: COMMODITY REVENUE. TARIFFS. ALLOCATION OF REVENUES AND CONDUCTION OF TEST

		Exit tariffs (€/GWh)				
Commodity revenue (€)	5,101,672	**IP 1**	**IP 2**	**IP Exit 5**	**IP 3**	**Consumption**
Entry share	1,913,127	5	5	5	5	5
Exit share	3,188,545					
Entry revenues dedicated for Intra	1,642,500	Acc. to Art 5(5)(c)			**Entry Tariffs (€/GWh)**	
Entry revenues dedicated for Cross	270,627	Acc. to Art 5(5)(b)			**LNG**	3
Exit revenues from Intra	2,737,500				**IP 1**	3
Exit revenues from Cross	451,045				**IP Entry 4**	3
Revenue for Intra	4,380,000				**IP 2**	3
Revenue for Cross	721,672				**IP 3**	3
Cost driver for Entry Intra	**154,150**					
Cost driver for Exit Intra	154,150					**Test**
Cost driver for Intra	308,301				**Ratio intra**	14.2069
Cost driver for Entry Cross	**43,472**				**Ratio cross**	8.2699
Cost driver for Exit Cross	43,793				**CAA**	52.83 %
Cost driver for Cross	87,264				**justification required**	

Table 25: Commodity revenue, tariffs, allocation of revenues and conduction of test

1) Compare 90.21 as the total of the entry column in blue in the previous table, and the total of Exit columns IP 1, IP 2, IP Exit 5 and IP 3 (90.21 = 13.8 + 14.4 + 47.3 + 14.7), taking into account rounded values in the previous blue table.

The allocation of entry commodity revenues to cross-system use (blue font) is made in accordance to Article 5(5)(b). It is the Sumproduct of the entry tariffs and the entry commodity allocated to cross-system use (Table C, blue font). The rest of the entry commodity revenues are then allocated to intra-system use.

Exit commodity revenues are determined by the exit flows and the exit commodity tariffs. The commodity tariff for the intra-system exit (Consumption point) times its respective exit flow determines the exit commodity revenue from intra-system use. The rest of the exit commodity revenues are therefore coming from cross-system use.

The cost drivers for intra- and cross-system uses are determined by adding the drivers shown in Table C. Cost drivers for entry Intra (red font) is the addition of the Driver for each entry (Intra-Use) which were introduced in Table C (red font). Cost driver for entry Cross is calculated analogously. Cost driver exit cross and intra are simply the addition of the drivers for exit points in Table C. Cost driver exit intra is the cost driver of the consumption point and cost driver exit cross the addition of the other four drivers for exit points.

The values of Cost driver for Intra is now the addition of the respective intra drivers for the entry and exit. Cost driver cross is the addition of the respective cross drivers for both entry and exit. These two parameters represent $Driver_{comm}^{intra}$ and $Driver_{comm}^{cross}$ from Article 5 in the TAR NC.

The amount of $Revenue_{comm}^{intra}$ which is stated in the TAR NC is the addition of both abovementioned commodity revenues for intra-system use. The parameter $Revenue_{comm}^{cross}$ is therefore the addition of both the exit and entry commodity revenues from cross-system use.

With those four parameters highlighted in blue, the CAA can be performed as described in the TAR NC.

The ratios for intra and cross can be calculated and the parameter $Comp_{comm}$ (CAA in the table above) can be tested to be above 10 %. The NRA has therefore to give justification regarding this value for the commodity-based CAA.

Annex D

Article 8 – Process of Capacity Weighted Distance Counterfactual Application

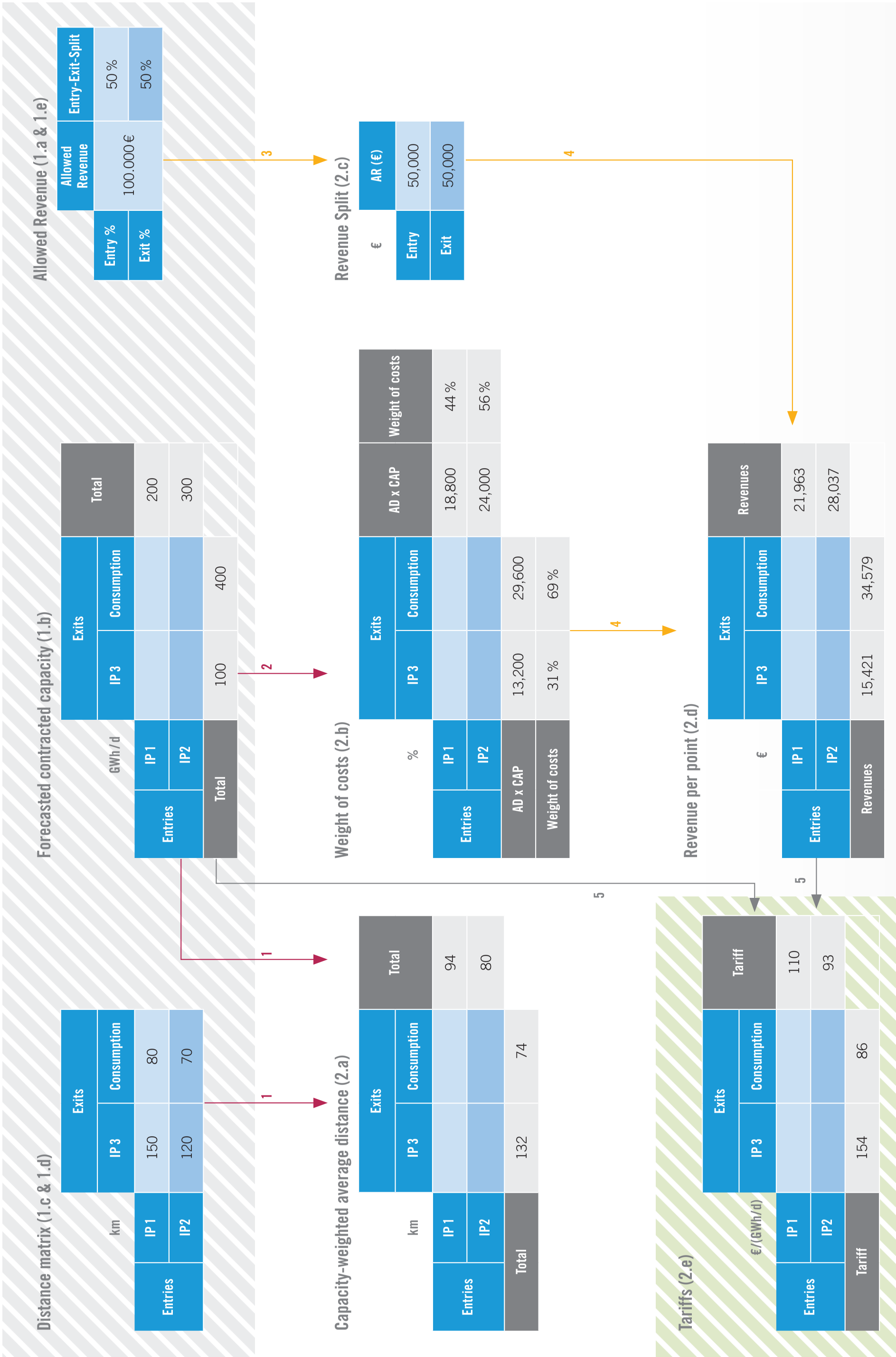


Figure 57: Process for CWD counterfactual

Annex E

Article 8 – Example of Capacity Weighted Distance Counterfactual

This example intends to illustrate the schematic approach described in Annex D. It depicts a fictional network but follows the approach set out in Article 8 for the CWD counterfactual comparison. **Its goal is to derive capacity tariffs based on CWD** at entry and exit points.

This is a one-TSO entry-exit system (or 'entry-exit zone' EEZ 1) with the following points.

LIST OF NETWORK POINTS

Points	Type	Longitude	Latitude	Points	Entry	Exit
A	Storage	19	11	A	Yes	Yes
B	IP	13	25	B	Yes	Yes
C	Storage	8	11	C	Yes	Yes
D	Production	12	22	D	Yes	No
E	Production	7	15	E	Yes	No
F	LNG	2	17	F	Yes	No
G	Production	20	18	G	Yes	No
H	Consumption	9	20	H	No	Yes
I	IP	2	22	I	Yes	Yes
J	IP	25	6	J	Yes	No
K	IP	25	3	K	Yes	Yes
L	LNG	21	26	L	Yes	No
M	IP	23	19	M	Yes	Yes
N	Consumption	16	14	N	No	Yes
O	Consumption	21	14	O	No	Yes
P	Consumption	9	22	P	No	Yes
Q	IP	11	1	Q	Yes	No
R	IP	6	3	R	No	Yes
S	Other	21	18,3	S	No	No
T	Other	19,4	14	T	No	No

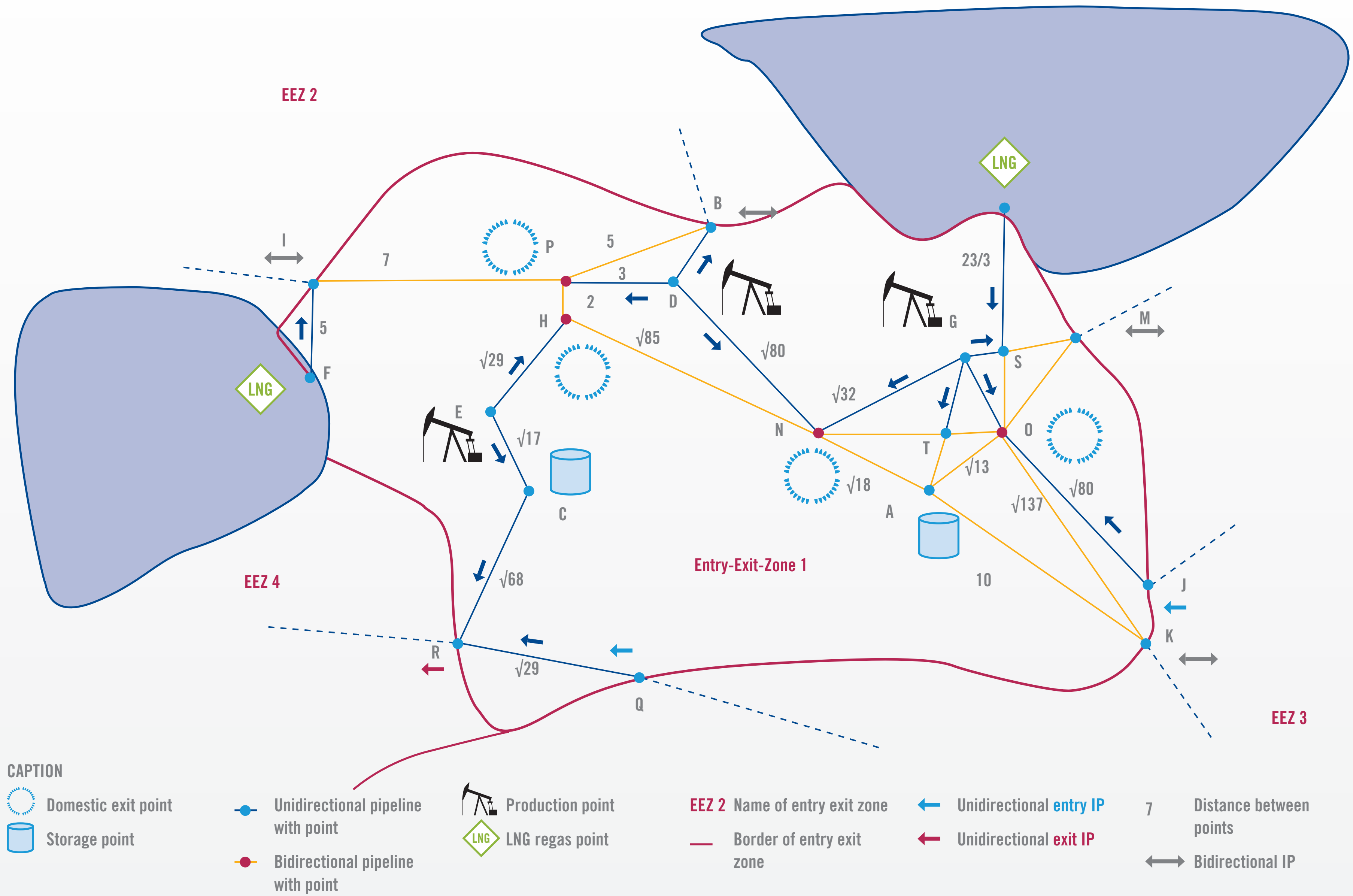
Table 29: List of network points

The TSO network is made of 26 points:

- **13 entry points** (including 2 storage points only connected to this TSO, 6 IPs allowing entry, 3 internal production points, and 2 LNG regasification points)
- **11 exit points** (including 2 storage points only connected to this TSO, 5 IPs allowing exit, and 4 consumption points)
- **2 other points** (S and T) at pipeline junctions, used only for distance calculations.

The map of the network is depicted on the next page.

Figure 58: Map of the network



ASSUMPTIONS:

- The TSO is connected to other systems and TSOs, and the system border is in red.
- Some pipelines are **bidirectional** (in yellow), others are **unidirectional** (in blue). Some IPs allow bidirectional flow (such as I), others only allow unidirectional flow (such as Q, which only allows entry).
- LNG regasification terminals are connected to the TSO network. It is not possible to flow gas to an LNG regasification terminal.
- Production points (e.g. 'E') are connected to the TSO network. It is not possible to flow gas **to** a production point.
- Flowing gas from a storage point to another storage point is theoretically possible (e.g. for arbitrage reasons).
- Distances calculated here (**in km**, but there is no mandatory unit in Article 8) are based on pipeline routes. For the exercise, the straight line between points was used, explaining why distances often display square roots[1]. For clarity, some distances are indicated in the right-hand side of the picture.
- **A short description of each point of this TSO:**
  - **Point A:** a storage point connected to the TSO bidirectional network, near consumption points,
  - **Point B:** an IP allowing bidirectional flows, connected to the TSO bidirectional network, near consumption and production points,
  - **Point C:** a storage point purely for cross-system use, fed by production, not connected to the domestic bidirectional network (no flows from/to it),
  - **Point D:** a production point connected to the TSO bidirectional network, near consumption points and an IP,
  - **Point E:** a production point connected to the TSO bidirectional network, near a consumption point and a storage for cross-border use,
  - **Point F:** an LNG point connected via a unidirectional pipeline to the TSO bidirectional network and to an IP allowing bidirectional flows,
  - **Point G:** a production point connected to the TSO bidirectional network and near consumption points,
  - **Point H:** a consumption point connected to the TSO bidirectional network, near a production point,
  - **Point I:** an IP allowing bidirectional flows, connected to the TSO bidirectional network, near a consumption point and an LNG point,
  - **Point J:** an IP only allowing entry flows, located near a consumption point, indirectly connected to the TSO bidirectional network,
  - **Point K:** an IP allowing bidirectional flows, connected to the TSO bidirectional network, near a storage point and a consumption point,
  - **Point L:** an LNG point connected via a unidirectional pipeline to the TSO bidirectional network,
  - **Point M:** an IP allowing bidirectional flows, connected to the TSO bidirectional network and near a consumption point,
  - **Point N:** a consumption point connected to the TSO bidirectional network, near storage, production and other consumption points,

1) In line with Article 8, distances follow the pipeline approach (airline is not allowed). There is no mandatory distance unit (it could be 'km' or 'mile'...) but we chose the standard 'km'. The map displays points with integer coordinates, for simplicity. Distances between points are calculated using the straight line. To calculate such distances, the Pythagorean Theorem is therefore used, where the straight line is the hypotenuse of a triangle where the entry and exit points considered are at each end of the hypotenuse. This explains why the length of the straight line often appears as a square root.

– **Point O:** a consumption point connected to the TSO bidirectional network, near a storage point, a production point and IPs,

– **Point P:** a consumption point connected to the TSO bidirectional network, near another consumption point, a production point and IPs,

– **Point Q:** an IP only allowing entry flows, not connected to the TSO bidirectional network (no flows from/to it), purely for cross-system use,

– **Point R:** an IP only allowing exit flows, not connected to the TSO bidirectional network (no flows from/to it), purely for cross-system use,

– **Point S:** a point where unidirectional pipelines from production and LNG points connect to the TSO bidirectional network,

– **Point T:** a point where a pipeline from production connects to the TSO bidirectional network.

Assumptions regarding technical capacity and forecasted bookings at entry and at exit points are in the next 2 tables (points S and T are not represented because they are neither entry nor exit points). Capacity unit is for instance **kWh/d**, and there is no specified capacity unit in Article 8 of TAR NC (others are possible).

This is a pure example, where units are not under the focus, and therefore data for revenues and capacity tariffs should be rescaled to reflect the reality of TSO tariffs. Tariffs derived with the CWD counterfactual are defined for the same runtime as tariffs for the RPM, i.e. per year. In the current case, tariffs are therefore in **(kWh/d)/y**.

CAPACITY DATA

	Entry points	En Technical Cap	F'st Contracted En
Storage	A	8	4
IP	B	70	68
Storage	C	7	4
Production	D	10	4
Production	E	10	6
LNG	F	30	30
Production	G	20	20
IP	I	10	3
IP	J	10	8
IP	K	60	60
LNG	L	30	30
IP	M	80	80
IP	Q	90	20
	Exit points	**Ex Technical Cap**	**F'st Contracted Ex**
Storage	A	8	1
IP	B	100	90
Storage	C	7	2
Consumption	H	60	60
IP	I	50	50
IP	K	60	40
IP	M	90	90
Consumption	N	20	10
Consumption	O	50	50
Consumption	P	10	10
IP	R	97	24

Table 30: Capacity data

Assumptions and constraints on revenues:

- TSO revenue to be covered by capacity charges supposed to be € 1,000,
- Mandatory value of entry-exit split is **50 %** as per Article 8(1)(e),
- TSO entry revenues to recover are therefore 50 % of € 1,000, i.e. € 500,
- TSO exit revenues to recover are therefore 50 % of € 1,000, i.e. € 500.

The next step is to calculate distances between points and then to consider only those which are relevant for a flow scenario, as per Article 8 of CWD counterfactual.

The next table presents the results of pipeline route distances between points, on the basis of the network map and taking into account flow scenarios only. This table will be referred to as the **'Main table'**.

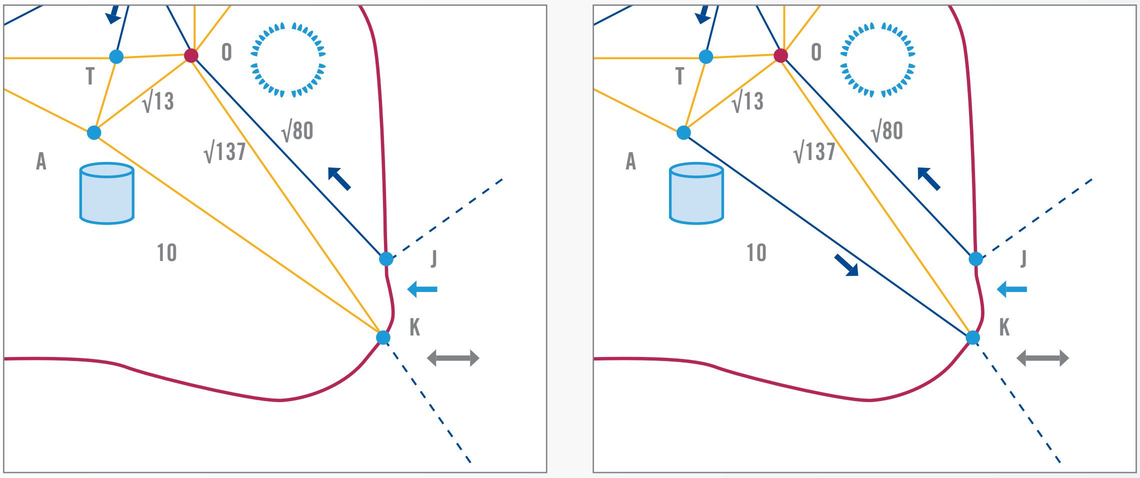
SHORTEST PIPELINE PATH BETWEEN 2 POINTS, WHEN FLOW SCENARIO IS RELEVANT (DISTANCES)

	Exit points													
Entry points	**A**	**B**	**C**	**H**	**I**	**K**	**M**	**N**	**O**	**P**	**R**	**ADen**	**Sum prod**	**Wcen**
A	**0.0**	20.5	**0.0**	13.5	22.5	10.0	9.0	4.2	3.6	15.5	**0.0**	13.40	6491.82	0.8 %
B	20.5	**0.0**	**0.0**	7.0	12.0	30.5	26.6	16.2	21.2	5.0	**0.0**	19.06		20.0 %
C	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	8.2	8.25		0.5 %
D	13.2	3.2	**0.0**	5.0	10.0	23.2	19.3	8.9	13.9	3.0	**0.0**	11.43		0.7 %
E	18.8	12.4	4.1	5.4	14.4	28.8	25.0	14.6	19.6	7.4	12.4	16.59		1.5 %
F	27.5	17.0	**0.0**	14.0	5.0	37.5	33.6	23.2	28.2	12.0	**0.0**	22.28		10.3 %
G	7.1	21.9	**0.0**	14.9	23.9	15.8	3.2	5.7	4.1	16.9	**0.0**	13.50		4.2 %
I	22.5	12.0	**0.0**	9.0	**0.0**	32.5	28.6	18.2	23.2	7.0	**0.0**	19.74		0.9 %
J	12.5	30.2	**0.0**	23.2	32.2	20.6	14.3	13.9	8.9	25.2	**0.0**	21.64		2.7 %
K	10.0	30.5	**0.0**	23.5	32.5	**0.0**	17.1	14.2	11.7	25.5	**0.0**	23.00		21.3 %
L	15.6	33.2	**0.0**	26.2	35.2	23.7	9.8	17.0	12.0	28.2	**0.0**	22.99		10.6 %
M	9.0	26.6	**0.0**	19.6	28.6	17.1	**0.0**	10.4	5.4	21.6	**0.0**	20.20		24.9 %
Q	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	5.4	5.39		1.7 %
ADex	14.49	25.90	4.12	16.85	23.26	24.34	20.01	14.10	13.40	17.51	7.16			100.0 %
Sum Prod	8460.85													
Transpose	1	90	2	60	50	40	90	10	50	10	24			
Wcex	0.2 %	27.6 %	0.1 %	12.0 %	13.7 %	11.5 %	21.3 %	1.7 %	7.9 %	2.1 %	2.0 %	100.0 %		

Table 31: Distance matrix and calculations

- Entry points are in rows, exit points are in columns.
- **Distance between two points may theoretically vary depending on the flow scenario** in case 2 points are connected via at least one unidirectional pipeline[1]. For example, in the current configuration the shortest path for gas between storage point 'A' and bidirectional IP 'K' is simply along bidirectional pipeline AK, and distance between A and K is therefore 10 km. However, in a modified configuration where pipeline AK would only allow flows from A to K (not anymore between K and A), it would be still possible to flow gas at entry point K to inject gas in storage A but along the pipeline via consumption point O. Distance for AK would still be 10 km, but distance for KA would be the sum of distances for KO and OA, that is 15.3 km.

1) Note that in Article 8 of TAR NC, the calculation of the average distance for an entry point AD_{En} and the calculation for an exit point AD_{Ex} both refer to the same distance $D_{En,Ex}$. For flow scenario reasons, Article 8 should actually make a distinction between $D_{A,B}$ and $D_{B,A}$.



Original case: distance for flow scenario is the same for AK and KA

Variant: distance for flow scenario is now longer for KA because pipeline AK is now unidirectional

Figure 59: Impact of flow scenarios on calculated distances

- **If an entry point and an exit point are not connected according to a flow scenario**, the distance between them in both directions is indicated by a '**0**' written in red in the previous table. For example, storage point A and storage point C are not connected according to a flow scenario: it is impossible to flow gas within the network of the TSO from A to C or from C to A because of unidirectional pipelines (section H to C is the problem in the 'A to C' direction, section C to E is the problem in the 'C to A' direction).
- Flows from/to the same point are not considered as valid flow scenarios, and are also marked with a '**0**' in red (e.g. impossible to flow gas from A to A).
- Points S and T do not appear in the table since they are not relevant in tariff derivation for the CWD counterfactual (neither entry, nor exit points).

Example of non-zero distance calculation:

distance $D_{A,B}$ between point A and point B is the shortest pipeline distance between these points which respects the flow scenario principle. It is not possible to connect A to B by flowing gas between N and D, because this section is a unidirectional pipeline between production plant D and the bidirectional network at consumption point N (there is no distance from N to D identified as such in the distance table, while distance from D to N is positive). The next-shortest pipeline is the one via points H and P. Thus, distance between A and B is the sum of distances for sections A to N, N to H, H to P, and P to B. The table gives 20.5 km for distance AB. The same calculations are performed for all the table.

Considering the **case of entry point A**, the table indicates the following results:

- **Positive distances** for points B, H, I, K, M, N, O, and P which may be connected with A because of the existence of a flow scenario.
- **Zero distance** to some exit points due to the lack of a flow scenario for the following reasons: problem of unidirectional pipelines (points C and R), or no flow from and to the same point (point A).

The following step (as per Article 8(2)(a)) is to calculate weighted average distances (WADs) for entry points (AD_{En}) and exit points (AD_{Ex}). The result of calculations also appears in Table 31[1)]. No (further) clusters of points A to R are considered here, for simplicity.

1) As indicated in the previous footnote, it is important to notice that the value of $D_{En,Ex}$ may be different for WAD calculations at entry points and at exit points, due to the flow scenario constraint.

WADs FOR ENTRY POINTS

The formula for entry points in Article 8 is as follows.

$$AD_{En} = \frac{\sum_{all\ Ex} CAP_{Ex} \times D_{En,Ex}}{\sum_{all\ Ex} CAP_{Ex}}$$

Distances D_{En},E_x have been calculated according to the shortest pipeline route approach.

It is important to note that, since some distances have been marked as '**0**' because of the impossibility of a flow scenario between entry point P1 and exit point P2 , it is also necessary to mark as '**0**' the forecasted contracted capacities at P2, otherwise WAD for P1 will be underestimated. **The lack of a flow scenario between two points implies to amend both distances and capacities used for calculations.**

Therefore, for entry points, the following matrix of corrected exit forecasted contracted capacities is used for ADEn derivation, and it displays '**0**' in red where applicable.

CAPACITY FOR AD_{en}

	Entry												
Exit	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**I**	**J**	**K**	**L**	**M**	**Q**
A	**0**	1	**0**	1	1	1	1	1	1	1	1	1	**0**
B	90	**0**	**0**	90	90	90	90	90	90	90	90	90	**0**
C	**0**	**0**	**0**	**0**	2	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
H	60	60	**0**	60	60	60	60	60	60	60	60	60	**0**
I	50	50	**0**	50	50	50	50	**0**	50	50	50	50	**0**
K	40	40	**0**	40	40	40	40	40	40	**0**	40	40	**0**
M	90	90	**0**	90	90	90	90	90	90	90	90	**0**	**0**
N	10	10	**0**	10	10	10	10	10	10	10	10	10	**0**
O	50	50	**0**	50	50	50	50	50	50	50	50	50	**0**
P	10	10	**0**	10	10	10	10	10	10	10	10	10	**0**
R	**0**	**0**	24	**0**	24	**0**	**0**	**0**	**0**	**0**	**0**	**0**	24
Total	**400**	**311**	**24**	**401**	**427**	**401**	**401**	**351**	**401**	**361**	**401**	**311**	**24**

Table 32: Exit forecasted contracted capacity matrix

For example, the weighted average distance for entry point A is calculated below.

$$AD_{EnA} = \frac{0\times0 + 90\times20.46 + \cdots + 60\times13.46 + \cdots + 0\times0 + 0\times0}{0 + 90 + \cdots + 60 + \cdots + 0 + 0} = 13.40$$

The average distance for entry point A is 13.40 km. The same type of calculations applies for the other entry points. Results for all entry points are in the **Main Table**.

WADS FOR EXIT POINTS

For exit points, the formula is as follows, with distances taken from the **Main Table**.

$$AD_{Ex} = \frac{\sum_{all\ En} CAP_{En} \times D_{En,Ex}}{\sum_{all\ En} CAP_{En}}$$

As with entry points, since some distances have been marked as '**0**' because of the impossibility of a flow scenario between entry point P1 and exit point P2, it is also necessary to mark as '**0**' the forecasted contracted capacities at P1, otherwise average exit distances will be underestimated. **Again, the lack of a flow scenario between two points implies to amend both distances and capacities used for calculations.**

Therefore, for exit points, the following matrix of corrected entry forecasted contracted capacities is used for AD_{Ex} derivation.

CAPACITY FOR AD_{ex}

	Exit									
Entry	**A**	**B**	**C**	**H**	**I**	**K**	**M**	**N**	**O**	**P**	**R**
A	**0**	4	**0**	4	4	4	4	4	4	4	**0**
B	68	**0**	**0**	68	68	68	68	68	68	68	**0**
C	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	4
D	4	4	**0**	4	4	4	4	4	4	4	**0**
E	6	6	6	6	6	6	6	6	6	6	6
F	30	30	**0**	30	30	30	30	30	30	30	**0**
G	20	20	**0**	20	20	20	20	20	20	20	**0**
I	3	3	**0**	3	**0**	3	3	3	3	3	**0**
J	8	8	**0**	8	8	8	8	8	8	8	**0**
K	60	60	**0**	60	60	**0**	60	60	60	60	**0**
L	30	30	**0**	30	30	30	30	30	30	30	**0**
M	80	80	**0**	80	80	80	**0**	80	80	80	**0**
Q	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	20
Total	**309**	**245**	**6**	**313**	**310**	**253**	**233**	**313**	**313**	**313**	**30**

Table 33: Entry forecasted contracted capacity matrix

For example, the weighted average distance for exit point A is calculated below.

$$AD_{ExA} = \frac{0{\times}0 + 68{\times}20.46 + \cdots + 30{\times}27.46 + \cdots + 0{\times}0 + 0{\times}0}{0 + 68 + \cdots + 30 + \cdots + 0 + 0} = 14.49$$

The average distance for exit point A is 14.49 km. The same type of calculations applies for the other exit points. Results for all exit points are in the **Main Table**.

The next step is to calculate the weight of cost for entry and exit points, as per Article 8(2)(b).

WEIGHT OF COST FOR ENTRY POINTS

The formula is as follows.

$$W_{c,En} = \frac{CAP_{En} \times AD_{En}}{\sum_{all\ En} CAP_{En} \times AD_{En}}$$

Average entry distances calculated at the previous step are used, as well as the original table for forecasted contracted capacities at entry points (not the table with corrected capacities, because now there is no reference to exit points and the feasibility of flow scenarios). In the **Main Table**, the value of the denominator is named 'Sum prod' and is 6,491.82.

For example, the weight of cost for entry point A is calculated below, according to **Main Table** values.

$$W_{c,EnA} = \frac{CAP_{EnA} \times AD_{EnA}}{\sum_{all\ En} CAP_{En} \times AD_{En}} = \frac{4 \times 13.40}{6{,}491.82} \approx 0.8\%$$

It means that entry point A has to collect 0.8 % of entry revenues. Similar calculations apply for other entry points. Results for all entry points are in the **Main Table**.

The heaviest shares of entry costs have to be borne by entry IPs 'B', 'K', and 'M' with respective shares of 20.0 %, 21.3 % and 24.9 %. The lightest share of entry costs has to be borne by storage point C with a share of 0.5 %. The sum of weights over all entry points is of course 100 %.

WEIGHT OF COST FOR EXIT POINTS

The formula is as follows.

$$W_{c,Ex} = \frac{CAP_{Ex} \times AD_{Ex}}{\sum_{all\ Ex} CAP_{Ex} \times AD_{Ex}}$$

Average exit distances calculated at the previous step are used, as well as the original table for forecasted contracted capacities at exit points (not the table with corrected capacities, because now there is no reference to entry points and to the feasibility of flow scenarios). In the **Main Table**[1)], the value of the denominator is named 'Sum prod' and is 8,460.85.

For example, the weight of cost for exit point A is calculated below, according to the **Main Table** values.

$$W_{c,ExA} = \frac{CAP_{ExA} \times AD_{ExA}}{\sum_{all\ Ex} CAP_{Ex} \times AD_{Ex}} = \frac{1 \times 14.49}{8{,}460.85} \approx 0.2\%$$

It means that exit point A has to collect 0.2 % of exit revenues. Similar calculations apply for other exit points. Results for all exit points are in the **Main Table**.

The heaviest shares of exit costs have to be borne by exit IPs 'B' and 'M' with respective shares of 27.6 % and 21.3 %. The lightest share of exit costs has to be borne by storage point C with a share of 0.1 %. The sum of weights over all exit points is of course 100 %.

The next stage is to derive tariffs at entry and exit points (as per Article 8(2)(c) to (e)), prior to the adjustment for storage discounts (Article 9(1)).

1) To help with calculations, a row transposing the column of forecasted contracted exit bookings has been added in the table ('Transpose' row).

DERIVATION OF PRE-ADJUSTMENT ENTRY TARIFFS

The general formula for entry tariffs at a given Point P can be expressed as follows.

$$T_{EnP} = \frac{R_{EnP}}{CAP_{EnP}} = \frac{W_{c,EnP} \times R_{\Sigma En}}{CAP_{EnP}}$$

$R_{\Sigma En}$ is the value of TSO revenues to be collected from capacity at entry points (500 € here, as per assumptions).

For example, the tariff for entry point A is defined according to previous tables.

$$T_{EnA} = \frac{W_{c,EnA} \times R_{\Sigma En}}{CAP_{EnA}} \approx \frac{0.8\% \times 500}{4} \approx 1.0319$$

The pre-adjustment CWD counterfactual tariff at entry from storage point A is **1.0319 €/(kWh/d)/y**. Similar calculations are used to derive CWD tariffs at other entry points.

DERIVATION OF PRE-ADJUSTMENT EXIT TARIFFS

The general formula for exit tariffs at a given Point P can be expressed as follows.

$$T_{ExP} = \frac{R_{ExP}}{CAP_{ExP}} = \frac{W_{c,ExP} \times R_{\Sigma Ex}}{CAP_{ExP}}$$

$R_{\Sigma Ex}$ is the value of TSO revenues to be collected from capacity at exit points (€ 500 here, as per assumptions).

For example, the tariff for exit point A is defined according to previous tables.

$$T_{ExA} = \frac{W_{c,ExA} \times R_{\Sigma Ex}}{CAP_{ExA}} \approx \frac{0.2\% \times 500}{1} \approx 0.8564$$

The pre-adjustment CWD counterfactual tariff at entry from storage point A is **0.8564 €/(kWh/d)/y**. Similar calculations are used to derive CWD tariffs at other exit points.

DERIVATION OF POST-ADJUSTMENT TARIFFS

The full table with CWD tariffs at entry points, before and after the adjustment for storage discounts, is presented below.

Pre-adjustment entry tariffs and entry revenues: column T_{En} defines pre-adjustment entry tariffs. Column R_{En} indicates pre-adjustment total revenues collected at each entry point with the CWD counterfactual. The TSO collects €500 at entry points.

Post-adjustment entry tariffs and entry revenues: for entry points from storage facilities, a tariff discount is applied, as per Article 9(1). For simplicity, one assumes that the discount at entry points from storage facilities is 50%. This implies that pre-adjustment tariffs are divided by 2 for entry points from storages only (cf. *Ten_adjusted* column). Without any correction, the TSO would under-recover its allowed revenue at entry points of € 500 (cf. $R_{en\_adjusted}$ column). Therefore, adjusted tariffs are rescaled upwards by a multiplicative factor of 500/496.67, which gives the final entry tariffs (T_{en_final}) and the final entry revenues (R_{en_final}). The advantage of this multiplicative rescaling factor, compared to an additive rescaling factor, is that there is no change in the relative tariffs charged at entry points.

TARIFF TABLE AT ENTRY POINTS

					Storage adjustment at entry points					
Entry points	W_{cen}	R_{SumEn}	R_{En}	T_{En}	Storage?	$T_{En\_adjusted}$	$R_{En\_adjusted}$	T_{En_final}	R_{En_final}
A	0.8%	500	4.13	1.0319	yes	0.5159	2.0637	0.5194	2.0776
B	20.0%		99.81	1.4677	no	1.4677	99.8054	1.4776	100.4753
C	0.5%		2.54	0.6351	yes	0.3176	1.2702	0.3197	1.2788
D	0.7%		3.52	0.8800	no	0.8800	3.5199	0.8859	3.5436
E	1.5%		7.67	1.2778	no	1.2778	7.6668	1.2864	7.7182
F	10.3%		51.48	1.7159	no	1.7159	51.4760	1.7274	51.8215
G	4.2%		20.79	1.0394	no	1.0394	20.7879	1.0464	20.9275
I	0.9%		4.56	1.5203	no	1.5203	4.5610	1.5305	4.5916
J	2.7%		13.34	1.6670	no	1.6670	13.3361	1.6782	13.4257
K	21.3%		106.29	1.7714	no	1.7714	106.2852	1.7833	106.9987
L	10.6%		53.12	1.7708	no	1.7708	53.1244	1.7827	53.4810
M	24.9%		124.47	1.5559	no	1.5559	124.4740	1.5664	125.3095
Q	1.7%		8.30	0.4148	no	0.4148	8.2953	0.4175	8.3510
	100%		**500.00**				**496.67**		**500.00**

Table 34: Tariff table at entry points

The full table with CWD tariffs at exit points, before and after the adjustment for storage discounts, is presented below.

Pre-adjustment exit tariffs and exit revenues: column T_{Ex} defines pre-adjustment exit tariffs. Column R_{Ex} indicates pre-adjustment total revenues collected at each exit point with the CWD counterfactual. The TSO collects 500€ at exit points.

Post-adjustment exit tariffs and exit revenues: for exit points to storage facilities, a tariff discount is applied, as per Article 9(1). For simplicity, one assumes that the discount at exit points to storage facilities is 50%. This implies that pre-adjustment tariffs are divided by 2 for exit points to storages only (cf. $T_{Ex\_adjusted}$ column). Without any correction, the TSO would under-recover its allowed revenue at exit points of € 500 (cf. $R_{Ex\_adjusted}$ column). Therefore, adjusted tariffs are rescaled upwards by a multiplicative factor of 500/499.33, which gives the final exit tariffs (T_{Ex_final}) and the final exit revenues (R_{Ex_final}). The advantage of this multiplicative rescaling factor, compared to an additive rescaling factor, is that there is no change in the relative tariffs charged at exit points.

TARIFF TABLE AT EXIT POINTS

					Storage adjustment at exit points				
Exit points	W_{cex}	R_{SumEx}	R_{Ex}	T_{Ex}	Storage?	$T_{Ex\_adjusted}$	$R_{Ex\_adjusted}$	T_{Ex_final}	R_{Ex_final}
A	0.2 %	500	0.86	0.8564	yes	0.4282	0.4282	0.4288	0.4288
B	27.6 %		137.77	1.5308	no	1.5308	137.7703	1.5328	137.9557
C	0.1 %		0.49	0.2437	yes	0.1218	0.2437	0.1220	0.2440
H	12.0 %		59.75	0.9959	no	0.9959	59.7530	0.9972	59.8334
I	13.7 %		68.72	1.3744	no	1.3744	68.7196	1.3762	68.8121
K	11.5 %		57.54	1.4385	no	1.4385	57.5409	1.4405	57.6183
M	21.3 %		106.44	1.1826	no	1.1826	106.4365	1.1842	106.5797
N	1.7 %		8.33	0.8335	no	0.8335	8.3350	0.8346	8.3462
O	7.9 %		39.59	0.7919	no	0.7919	39.5933	0.7929	39.6466
P	2.1 %		10.35	1.0348	no	1.0348	10.3478	1.0362	10.3617
R	2.0 %		10.16	0.4233	no	0.4233	10.1599	0.4239	10.1736
	100.0 %		**500.00**				**499.33**		**500.00**

Table 35: Tariff table at exit points

In conclusion, as described in the TAR NC, the CWD counterfactual is obligatory for the purpose of consultation per Article 26 unless the proposed RPM fully coincides with the CWD counterfactual.

Annex F

Article 9 – Example of a Discount Reduction at Storage Facilities with Access to More than One Entry–Exit System

As a default rule, the TAR NC states that storage tariffs require a 50 % discount, with the potential for higher discounts up to 100 %. However, there is the potential for an exemption where the location of storage results in the entry and exit of gas being used as an IP. Below is an example of how this is currently managed in Germany.

For gas storage facilities with access to more than one entry-exit-system an exemption rule applies. Nevertheless, the TSOs have to offer the same discount of 50 % for entry and exit capacity even at those storage facilities – so that network users are allowed to register for a 50 % discount – in case the storage operator is able to meet the following conditions:

1. The storage operator has to keep two gas accounts per customer[1]:

   (a) One account for the discounted gas volumes (50 % discount), and

   (b) One account for the non-discounted gas volumes.

2. The storage operator is obliged to track on an hourly basis and for each direction (entry/exit) which volumes are booked on the account for discounted volumes and which are booked on the non-discounted account. The TSOs are to be provided with the information. Therefore, and in simplified terms, the choice of booking on either account by network users is an indication *ex ante* for the TSO on whether network users intend to use the storage facility 'as a standard storage' and/or 'as an IP'.

3. The storage operator has to ensure that no cross-bookings from the discounted to the non-discounted accounts are done.

In case the storage is used to transfer capacities from one entry-exit-system to another entry-exit-system and a discount was granted, a discount reduction for the transferred volumes applies. Therefore, the discount reduction corresponds to an *ex post* corrective charge to take account of the actual use of the storage facility 'as an IP' by network users.

1) In other systems, for example in Austria, there may be a solution implemented involving only one account per entry-exit system side.

APPLICATION AND CALCULATION

In case the storage operator's customer is using storage facility to transfer capacity from one entry-exit-system to another entry-exit-system, two possible options are given. Capacity could be either transferred between:

1. The accounts for non-discounted capacities (case 1), or between
2. The accounts for discounted capacities (case 2).

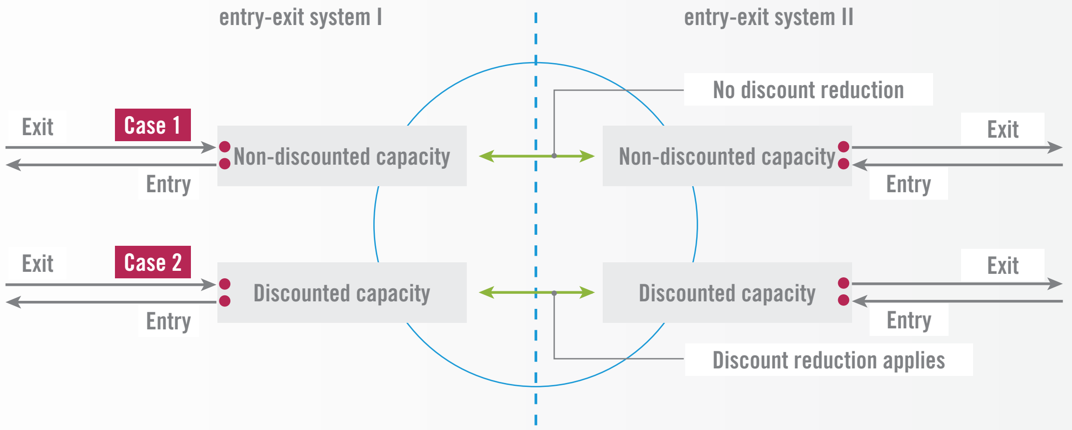


Figure 60: Discount reduction for some storage facilities in Germany

Cross-bookings from the discounted to the non-discounted account are prohibited.

As in case 1) neither a discount for the entry capacity nor for the exit capacity was granted, no discount reduction applies. Actually the same price as for the IP was paid and no discrimination of the competing IP is given.

In case 2), capacities have been injected and withdrawn at a discounted tariff. Consequently the storage operator has to apply to its customers a discount reduction to avoid a price discrimination towards the competing IP. The discount reduction is calculated as follows:

(a) The storage operator has to determine the maximum hourly capacity for each day on which gas has between transferred between both entry-exit-systems through the gas storage.

(b) The maximum hourly transferred capacity is subject to a storage discount reduction which consists of two components, one storage entry price component and one storage exit price component. The storage entry price component is the difference between the highest and lowest offered exit capacity tariff at the respective storage of that TSO from which the gas was injected. The storage exit price component is the difference between the highest and lowest offered entry capacity tariff of the adjacent TSO.

(c) Based on the determined storage entry and storage exit price components of the discount reduction as well as the maximum hourly capacity (see (a)), the discount reduction is calculated. The discount reduction to be paid to the TSO from which the gas was injected into the storage is calculated by multiplying the storage entry price component with the maximum hourly transferred capacity and a multiplier of 1.4. Further, the discount reduction to be paid to the TSO into which the gas from the storage was withdrawn is calculated by multiplying the storage exit price component with the maximum hourly transferred capacity and a multiplier of 1.4.

Consequently, for the bypassing of an IP through a storage a multiplier of 1.4 is applied for those gas volumes which were granted a discount before. The 40 % on top of the non-discounted tariff is used to restore tariff equality between tariffs at the bypassed IP and tariffs at the storage used as an IP. The discount reduction is collected by the storage operator for the benefit of both TSOs.

To sum up, there are four simple configurations at storage facilities connected to more than one entry-exit system (other configurations exist, where network users partly transfer gas and partly withdraw it into the TSO system from which it was previously injected, but these configurations are not considered here):

- **Case 1:** The network user registers on the non-discounted account of the storage operator, and they transfer gas from an entry-exit system to another. In such case, the storage facility is simply used as an IP. The network user pays what they should pay if the storage was an IP (no discount), there is no discrimination against a competing IP, and **there is no discount reduction**.
- **Case 2:** The network user registers on the discounted account of the storage operator, and they do not transfer gas from an entry-exit system to another. In such case, the storage facility is simply used as a 'standard' storage facility. The network user pays what they should pay for any 'standard' storage facility (the 50 % discount), there is no discrimination against an IP since the storage facility is not used 'as an IP', **and there is no discount reduction**.
- **Case 3:** The network user registers on the non-discounted account of the storage operator, but they do not transfer gas from an entry-exit system to another. There is no discrimination against an IP since the storage facility is not used 'as an IP'. **There is no discount reduction**, since no gas is flowed between entry-exit systems.
- **Case 4:** The network user registers on the discounted account of the storage operator, but they transfer gas from an entry-exit system to another. In such case, the storage is used as an IP. To avoid discrimination against some network users, **a discount reduction applies**.

Annex G

Article 10(3) – Example of Inter-TSO Compensation Mechanism Application in Multi-TSO Entry–Exit Systems within a Member State

Policy choices for ITC derivation are not the topic of the example as the ITC mechanism is subject to NRA decision. Article 10(3) of the TAR NC only gives general principles for the ITC establishment, and no specific requirements to follow.

This Annex describes the case of an entry-exit system with two TSOs applying jointly/separately the same RPM. Two examples of RPMs will be considered: postage stamp and CWD. Before considering the multi-TSO case, it is useful to take the benchmark situation where each TSO has a specific entry-exit system. In a second step, the two entry-exit systems are merged.

Before the merger:

- **Part I** presents the situation where the two TSOs apply separately the same RPM in their own entry-exit system.

After the merger:

- **Part II** considers the case where the two TSOs apply jointly the same RPM after the merging of the two previous entry-exit systems into one.
- **Part III** shows the case where the two TSOs apply separately the same RPM after the merging into one entry-exit system.

Part I SAME RPM FOR THE TWO TSOs IN DIFFERENT ENTRY–EXIT SYSTEMS

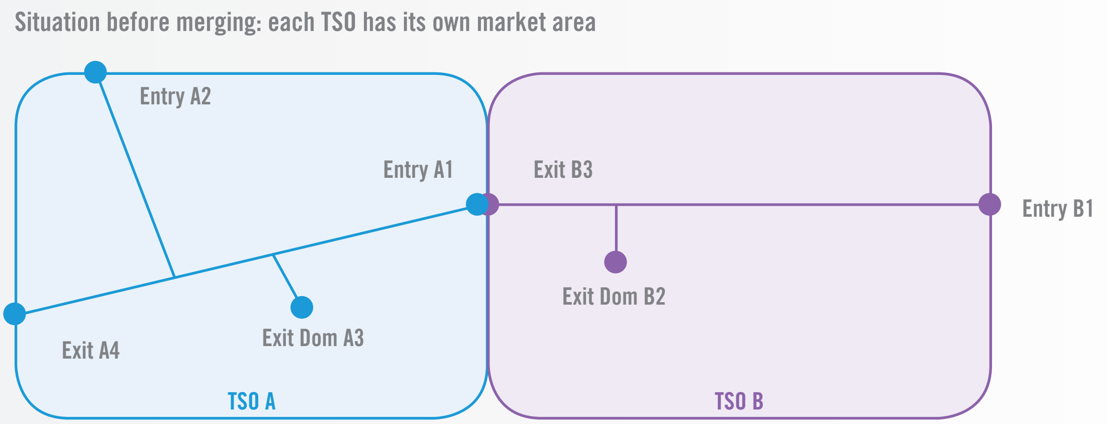


Figure 61: Map of networks before the merger

Assumptions regarding technical and forecasted capacity bookings, as well as allowed revenues, are given in the following table. The entry-exit split is calculated with data on forecasted capacity bookings, with the same equality in the distribution of entry and exit bookings for both TSOs, half capacity being booked in entry and half in exit.

INPUT DATA

		Technical cap. – GWh/h	Forecast – GWh/h	Allowed Revenue – m€	Entry/Exit Split: Entry	Entry/Exit Split: Exit
TSO A	Entry A1	10	9	70 m€	50 %	50 %
	Entry A2	4	2			
	Exit Dom A3	11	10			
	Exit A4	3	1			
TSO B	Entry B1	13	12	65 m€	50 %	50 %
	Exit Dom B2	3	3			
	Exit B3	10	9			

Table 36: Input data for networks before the merger

Then, tariffs are calculated in the case of the postage stamp RPM and following the rules of the CWD counterfactual, according to Article 8.

- **For postage stamp**, entry (resp. exit) tariffs are derived for each TSO by multiplying the allowed revenue by the entry (resp. exit) share of revenues, and dividing the result by total forecasted entry (resp. exit) bookings. Tariffs are identical for all points in entry and all points in exit: this is a result of postage stamp. This is shown in the table below.

TARIFFS €/(kWh/h)/a			
		Postage Stamp	CWD
TSO A	Entry A1	3.18	3.07
	Entry A2	3.18	3.67
	Exit Dom A3	3.18	3.00
	Exit A4	3.18	5.00
TSO B	Entry B1	2.71	2.71
	Exit Dom B2	2.71	2.38
	Exit B3	2.71	2.82

Table 37: Postage stamp tariffs before the merger

- **For CWD**, given the 2 cost drivers, calculations are more complex. Compared to postage stamp, it is necessary to consider distances between points. In accordance with Article 8 on CWD counterfactual, distance is here supposed to be measured by the shortest pipeline distance, which is the actual distance along pipelines that is necessary to connect two points of the network. Tariffs derived with the CWD RPM are presented in the above table, but the steps to calculate them are developed below.

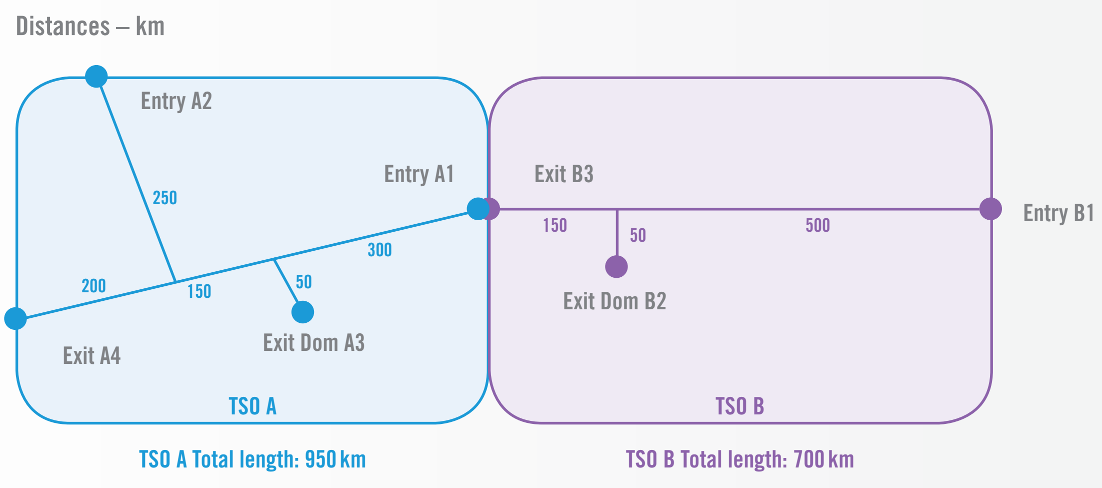


Figure 62: Distance map before the merger

For each TSO, distances between entry and exit points are summarised in the following table.

DISTANCE MATRICES			
		Exit Dom A3	Exit A4
TSO A	Entry A1	350	650
	Entry A2	450	450
		Exit Dom B2	Exit B3
TSO B	Entry B1	550	650

Table 38: Distance table before the merger

Then it is necessary to proceed with the CWD calculations for each TSO in the multi-TSO system, as explained in figure 39.

TSO A		TSO B	
Allowed Revenues			
	70 m€		**65 m€**
E/E-Split			
Entry	50 %	**Entry**	50 %
Exit	50 %	**Exit**	50 %
Revenues			
Entry	35 m€	**Entry**	32.50 m€
Exit	35 m€	**Exit**	32.50 m€
Fcap – Proportions			
Entry A1	82 %	**Entry B1**	100 %
Entry A2	18 %	**Exit Dom B2**	25 %
Exit Dom A3	91 %	**Exit B3**	75 %
Exit A4	9 %		
Calculation of capacity-weighted average distance			
Entry A1	377	**Entry B1**	625
Entry A2	450	**Exit Dom B2**	550
Exit Dom A3	368	**Exit B3**	650
Exit A4	614		
Calculation of the weight of each point			
Entry A1	79 %	**Entry B1**	100 %
Entry A2	21 %	**Exit Dom B2**	22 %
Exit Dom A3	86 %	**Exit B3**	78 %
Exit A4	14 %		
Allocation of costs			
Entry A1	28 m€	**Entry B1**	32.50 m€
Entry A2	7 m€	**Exit Dom B2**	7.15 m€
Exit Dom A3	30 m€	**Exit B3**	25.35 m€
Exit A4	5 m€		
Determination of tariffs – €/kWh/h			
Entry A1	3.07	**Entry B1**	2.71 m€
Entry A2	3.67	**Exit Dom B2**	2.38 m€
Exit Dom A3	3.00	**Exit B3**	2.82 m€
Exit A4	5.00		

Table 39: Tariff derivation before the merger

- Entry and exit revenues are calculated by using the entry-exit split ('Revenues').
- Shares for bookings at each point are derived ('Fcap – Proportions').
- Capacity-weighted average distance for each entry (resp. exit) point is calculated by considering distance to all exit (resp. entry) points and weighting by capacity at these exit (resp. entry) points.
- Weight of each entry (resp. exit) point is calculated by comparing the product of its forecasted capacity bookings and its capacity-weighted average distance with the sum of the products for all entry (resp. exit) points.
- Allocation of costs is calculated by multiplying the weight of each entry (resp. exit) point by entry (resp. exit) revenues.

Finally, CWD tariffs are derived by dividing the costs allocated to each point by the forecasted bookings for this point. Then, the tariffs make it possible to obtain results for postage stamp and CWD in terms of revenues in the pre-merged case.

OBTAINED REVENUES

		Postage Stamp	CWD			Postage Stamp	CWD
TSO A	Entry A1	28.64 m€	27.67 m€	**TSO B**	Entry A1	32.50 m€	32.50 m€
	Entry A2	6.36 m€	7.33 m€		Entry A2	8.13 m€	7.15 m€
	Exit Dom A3	31.82 m€	30.00 m€		Exit Dom A3	24.38 m€	25.35 m€
	Exit A4	3.18 m€	5.00 m€				
					Sum	65.00 m€	65.00 m€
	Sum	70.00 m€	70.00 m€				

Table 40: Revenue derivation before the merger

PART II

SAME RPM APPLIED JOINTLY BY THE TWO TSOs IN THE SAME ENTRY-EXIT SYSTEM

If there is a merger of the 2 entry-exit systems, the joint application of the RPM by TSOs is the default approach, as per Article 10(1) of TAR NC.

After the merger into one entry-exit system, the former IPs that connected the previous entry-exit systems disappear, involving the need for revenue reallocation for each TSO. In the example here, points A1 (for TSO A) and B3 (for TSO B) disappear, and it is therefore necessary to recover the revenues formerly collected there at remaining points. The figure below presents the newly merged entry-exit system.

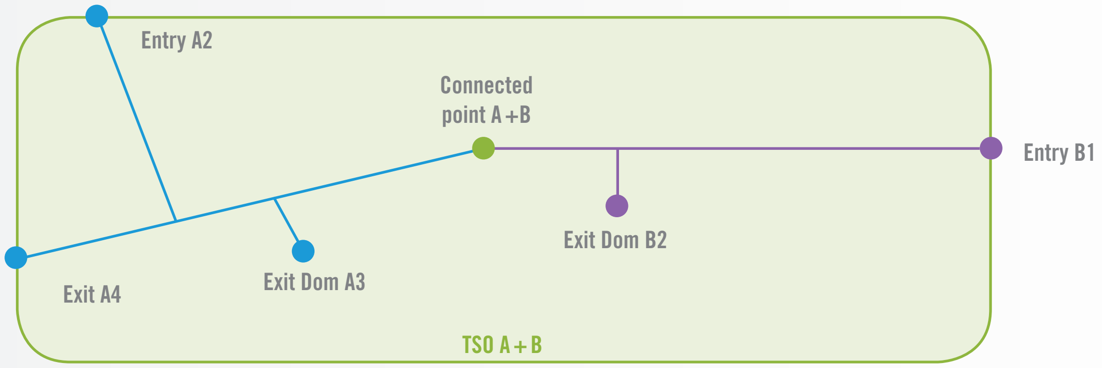


Figure 63: Map of the network after the merger

The following table represents the remaining points and their technical and forecasted booking capacities, in parallel with the same allowed revenue to recover for each TSO. It is interesting to note that the removal of points A1 and B3 due to the merger has changed the entry-exit split based on the forecasted bookings for both TSOs: it is now 15/85 for TSO A and 80/20 for TSO B.

INPUT DATA

		Technical cap. – GWh/h	Forecast – GWh/h	Entry/Exit Split: Entry	Entry/Exit Split: Exit	Revenue post-ITC payment
TSO A	Entry A2	4	2	15 %	85 %	70.00 m€
	Exit Dom A3	11	10			
	Exit A4	3	1			
TSO B	Entry B1	13	12	80 %	20 %	65.00 m€
	Exit Dom B2	3	3			
Sum	Entry	17	14	50 %	50 %	135.00 m€
	Exit	17	14			
				Postage Stamp	CWD	
			inter-TSO compensation (A -> B)	–7.32 m€	–6.41 m€	

ITC value is necessarily defined by RPM calculation (ex post).

Table 41: Input data after the merger (joint case)

In table 41, the objective is that TSOs A and B collect sufficient revenues after the **Inter-TSO Compensation (ITC) mechanism** adjustment in order to get their allowed revenues of 70 M€ and 65 M€. **In the joint RPM application presented here, the value of the ITC is determined by the RPM** (in some other cases, it might be set before the application of the RPM). The joint allowed revenue is first calculated (135 M€).

Then, as in Part I, tariffs are calculated in the case of the postage stamp RPM and following the rules of the CWD counterfactual. But from now on, calculations are made first at the joint level.

- **For postage stamp,** entry (resp. exit) tariffs are derived for the merged TSO by multiplying the joint allowed revenue and the new entry (resp. exit) share of revenues, and dividing the result by the new total forecasted entry (resp. exit) bookings. Tariffs are identical for all points in entry and all points in exit: this is a result of postage stamp. This is shown in the table below.

TARIFFS – €/(kWh/h)/a

		Postage Stamp	CWD			Tariff increases	Postage Stamp	CWD
TSO A	Entry A2	4.82	3.03		TSO A	Entry A2	51.53 %	–17.50 %
	Exit Dom A3	4.82	5.10			Exit Dom A3	51.53 %	70.04 %
	Exit A4	4.82	6.52			Exit A4	51.53 %	30.49 %
TSO B	Entry B1	4.82	5.12		TSO B	Entry B1	78.02 %	89.08 %
	Exit Dom B2	4.82	3.32			Exit Dom B2	78.02 %	39.37 %

Table 42: Tariffs after the merger (joint case)

- **For CWD**, again it is necessary to consider distances between points, with the same assumptions on distance calculations as before. Tariffs derived with the CWD RPM are presented in the above table, but the steps to calculate them are developed below. Compared to the separate application, there is one single distance matrix to consider in the joint application.

DISTANCE MATRIX

		Exit Dom A3	Exit A4	Exit Dom B2
joint application	Entry A2	450	450	900
	Entry B1	1,000	1,300	550

Table 43: Distance matrix after the merger (joint case)

But now, calculations consider distances for the joint entity made of the 2 TSOs. This means that the methodology is applied for the joint entity made of TSOs A and B. In the previous configuration (before the merger), it was not necessary to consider the distance between e.g. Entry A2 from TSO A and Exit B2 of TSO B. By contrast, the joint application in a merged entry-exit system requires that points from A and from B are considered together for flow scenarios. The figure below represents the merged entry-exit system with indication of distances for the application of CWD.

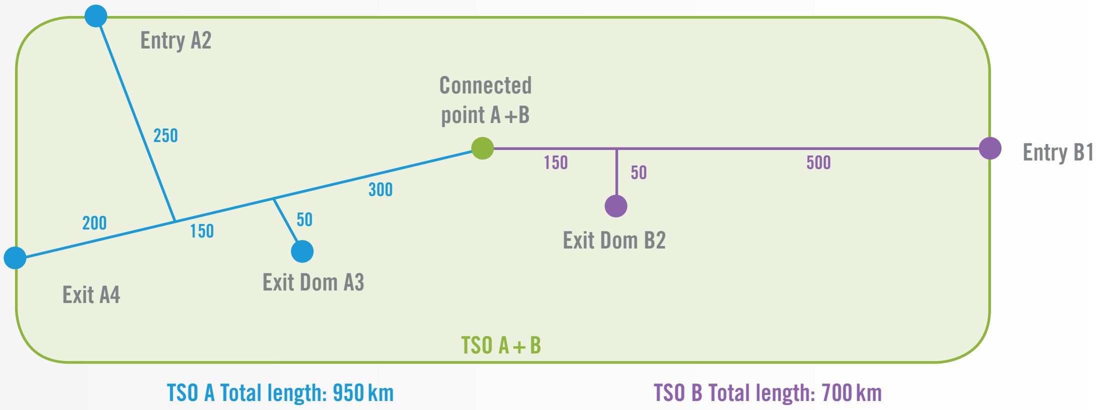


Figure 64: Distance map after the merger

Capacity Weighted Distance Approach (joint application)			
TSO A + B			
Allowed Revenues			
	135.00 m€		
E/E-Split			
Entry	50 %		
Exit	50 %		
Revenues			
Entry	67.50 m€		
Exit	67.50 m€		
Fcap – Proportions			
Entry A2	14 %	Entry B1	86 %
Exit Dom A3	71 %	Exit Dom B2	21 %
Exit A4	7 %		
Calculation of capacity-weighted average distance			
Entry A2	546	Entry B1	925
Exit Dom A3	921	Exit Dom B2	600
Exit A4	1,179		
Calculation of the weight of each point			
Entry A2	9 %	Entry B1	91 %
Exit Dom A3	76 %	Exit Dom B2	15 %
Exit A4	10 %		
Allocation of costs			
Entry A2	6.05 m€	Entry B1	61.45 m€
Exit Dom A3	51.01 m€	Exit Dom B2	9.96 m€
Exit A4	6.52 m€		
Determination of tariffs – €/kWh/h			
Entry A2	3.03	Entry B1	5.12
Exit Dom A3	5.10	Exit Dom B2	3.32
Exit A4	6.52		

Table 44: CWD tariff derivation after the merger (joint case)

Application – by each TSO – of the tariffs derived for the joint entity makes it possible to obtain results for postage stamp and CWD in terms of revenues. Note that the value of the ITC is still not determined at this stage.

OBTAINED REVENUES

		Postage Stamp	CWD			Postage Stamp	CWD
TSO A	Entry A2	9.64 m€	6.05 m€	**TSO B**	Entry B1	57.86 m€	61.4 m€
	Exit Dom A3	48.21 m€	51.01 m€		Exit Dom B2	14.46 m€	10.0 m€
	Exit A4	4.82 m€	6.52 m€				
	Sum	62.68 m€	63.59 m€		**Sum**	72 m€	71 m€
	ITC	7.32 m€	6.41 m€		**ITC**	−7.32 m€	−6.41 m€
	Revenues after ITC	70 m€	70 m€		**Revenues after ITC**	65 m€	65 m€

Table 45: Revenue table after the merger (joint case)

The ITC value is derived by difference between the allowed revenue of each TSO and the revenue collected via the tariffs derived for the joint entity. **The model indicates that an ITC of 7.32 M€ must be collected by TSO B** through its tariffs, and passed on to TSO A.

Compared to the pre-merged situation, the revenue reallocation after the removal of points A1 and B3 is performed via a tariff increase at all points in the postage stamp case, but via a mixed evolution of tariffs depending on the points in the CWD case. This is the same conclusion as the one to be displayed next in the separate case.

REVENUE SHORTFALL OF POINTS A1 AND B3 HAS TO BE COVERED AT OTHER POINTS

		Revenue to recover – m€		Revenue to recover – %		Tariff increase	
		Post Stamp	CWD	Post Stamp	CWD	Post Stamp	CWD
TSO A	Revenue A1	29 m€	28 m€	41 %	40 %	52 %	−17 % – 70 %
TSO B	Revenue B3	24 m€	25 m€	38 %	39 %	78 %	39 % – 89%

Table 46: Revenue reallocation after the merger (joint case)

PART III SAME RPM APPLIED SEPARATELY BY THE TWO TSOS IN THE SAME ENTRY-EXIT SYSTEM

As an alternative to the default approach of joint application in a merged entry-exit system, TSOs may apply separately the same RPM.

The maps used for the joint application in the same entry-exit system are also used here.

The following table represents the remaining points and their technical and forecasted booking capacities, in parallel with the same allowed revenue to recover for each TSO. As a reminder, the removal of points A1 and B3 has changed the entry-exit split based on the forecasted bookings for both TSOs: it is now 15/85 for TSO A and 80/20 for TSO B.

INPUT DATA							
		Technical cap. – GWh/h	Forecast – GWh/h	Entry/Exit Split: Entry	Entry/Exit Split: Exit	Revenue before ITC payment
TSO A	Entry A2	4	2	15 %	85 %	80,00 m€
	Exit Dom A3	11	10			
	Exit A4	3	1			
TSO B	Entry B1	13	12	80 %	20 %	55,00 m€
	Exit Dom B2	3	3			
			inter-TSO compensation (A -> B)	10 m€		

Due to NRA decision/calculation. In example, ITC value is chosen by an NRA decision (ex ante).

Table 47: Input data after the merger (separate case)

In the above table, one assumes that the NRA in charge of the merged entry-exit system decides that an **ITC of 10 M€** will be set up to ensure the revenue reallocation. The NRA decides that TSO A will charge tariffs at its remaining points in one revenue pot but for 2 purposes:

1) collecting its own allowed revenue (the same as in Part I), and
2) collecting the ITC.

Meanwhile, TSO B will charge tariffs at its remaining points for the sole purpose of collecting its own allowed revenue whose value is diminished by the predefined value of the ITC, in comparison to Part I. Therefore, TSO A will collect 80 M€ (instead of 70 M€ before the merger) and TSO B will collect 55 M€ (instead of 65 M€).

Then, as in Part I, and for comparison of tariffs derived from RPM application, tariffs are calculated in the case of the postage stamp RPM and following the rules of the CWD counterfactual.

- **For postage stamp,** entry (resp. exit) tariffs are derived for each TSO by multiplying the allowed revenue augmented by the ITC amount and the new entry (resp. exit) share of revenues, and dividing the result by the new total forecasted entry (resp. exit) bookings. Tariffs are identical for all points in entry and all points in exit: this is a result of postage stamp. The entry-exit split has changed for both TSOs A and B, after the removal of former IPs, which explains why tariffs will generally be different after the merger. For TSO A, which collects the ITC in this example, tariffs will necessarily increase at all points compared to the pre-merger situation, since an increased amount of revenues has to be collected from the same tariff charged at a reduced number of points. Therefore, at all points, postage stamp tariffs for the TSO in charge of collecting the ITC revenue always increase after the merger. This is shown in the table below.

TARIFFS – €/(KWh/h)/a

		Postage Stamp	CWD			Tariff increases	Postage Stamp	CWD
TSO A	Entry A2	6.15	20.00		TSO A	Entry A2	93.41 %	445.45 %
	Exit Dom A3	6.15	3.64			Exit Dom A3	93.41 %	21.21 %
	Exit A4	6.15	3.64			Exit A4	93.41 %	–27.27 %
TSO B	Entry B1	3.67	2.29		TSO B	Entry B1	35.38 %	–15.38 %
	Exit Dom B2	3.67	9.17			Exit Dom B2	35.38 %	284.62 %

Table 48: Tariffs after the merger (separate case)

- **For CWD,** again it is necessary to consider distances between points, with the same assumptions on distance calculations as before. Tariffs derived with the CWD RPM are presented in the above table.

  Compared to the pre-merger situation, the size of the distance matrices has shrunk due to the removal of points.

DISTANCE MATRICES

		Exit Dom A3	Exit A4
TSO A	Entry A2	450	450
		Exit Dom B2	
TSO B	Entry B1	550	

Table 49: Distance matrices after the merger (separate case)

Then the same type of calculations as those used in the pre-merged case are necessary to derive tariffs, and the results appear in the next figure.

Capacity Weighted Distance Approach (separate application)			
TSO A		**TSO B**	
Allowed Revenues			
	80.00 m€		55.00 m€
E/E-Split			
Entry	50 %	Entry	50 %
Exit	50 %	Exit	50 %
Revenues			
Entry	40.00 m€	Entry	27.50 m€
Exit	40.00 m€	Exit	27.50 m€
Fcap – Proportions			
Entry A2	100 %	Entry B1	100 %
Exit Dom A3	91 %	Exit Dom B2	100 %
Exit A4	9 %		
Calculation of capacity-weighted average distance			
Entry A2	450	Entry B1	550
Exit Dom A3	450	Exit Dom B2	550
Exit A4	450		
Calculation of the weight of each point			
Entry A2	100 %	Entry B1	100 %
Exit Dom A3	91 %	Exit Dom B2	100 %
Exit A4	9 %		
Allocation of costs			
Entry A2	40.00 m€	Entry B1	27.50 m€
Exit Dom A3	36.36 m€	Exit Dom B2	27.50 m€
Exit A4	3.64 m€		
Determination of tariffs – €/kWh/h			
Entry A2	20.00	Entry B1	2.29
Exit Dom A3	3.64	Exit Dom B2	9.17
Exit A4	3.64		

Table 50: CWD tariff derivation

Then, the tariffs make it possible to obtain results for postage stamp and CWD in terms of revenues in the separate case, with the assumption of an ITC of 10 M€ collected by TSO A.

OBTAINED REVENUES							
		Postage Stamp	CWD			Postage Stamp	CWD
TSO A	Entry A2	12.31 m€	40.00 m€	TSO B	Entry B1	44.00 m€	27.5 m€
	Exit Dom A3	61.54 m€	36.36 m€		Exit Dom B2	11.00 m€	27.5 m€
	Exit A4	6.15 m€	3.64 m€				
					Sum	55 m€	55 m€
	Sum	80 m€	80 m€				
					ITC	10.00 m€	10.00 m€
	ITC	– 10.00 m€	– 10.00 m€				
					Revenues after ITC	65 m€	65 m€
	Revenues after ITC	70 m€	70 m€				

Table 51: Revenue table after the merger (separate case)

Compared to the pre-merged situation, the revenues are reallocated after the removal of points A1 and B3 solved via a tariff increase at all points in the postage stamp case, but via a mixed evolution of tariffs depending on the points in the CWD case.

REVENUE SHORTFALL OF POINTS A1 AND B3 HAS TO BE RECOVERED AT OTHER POINTS							
		Revenue to recover – m€		Revenue to recover – %		Tariff increase	
		Post Stamp	CWD	Post Stamp	CWD	Post Stamp	CWD
TSO A	Revenue A1	29 m€	28 m€	41 %	40 %	93 %	–27 % – 445 %
TSO B	Revenue B3	24 m€	25 m€	38 %	39 %	35 %	–15 % – 285 %

Table 52: Revenue reallocation after the merger (separate case)

For CWD, the range of tariff evolutions is between – 27 % and + 445 % depending on the points. However, a weighted average increase in tariffs is for example + 83 % for TSO A, and + 45 % for TSO B, if weights are given by forecasted contracted capacity.

The table below provides a summary of tariffs derived for each of the 3 configurations analysed in this example. In the two multi-TSO system configurations, entry A1 and exit B3 are not anymore commercial points, due to the merger. Therefore, they have no tariffs.

SUMMARY OF TARIFFS IN ALL CONFIGURATIONS							
		Same RPM separately/ 2 one-TSO systems		Same RPM jointly/ 1 Multi-TSO system		Same RPM separately/ 1 Multi-TSO system	
		PS	CWD	PS	CWD	PS	CWD
TSO A	Entry A1	3.18	3.07	N/A	N/A	N/A	N/A
	Entry A2	3.18	3.67	4.82	3.03	6.15	20.00
	Exit Dom. A3	3.18	3.00	4.82	5.10	6.15	3.64
	Exit A4	3.18	5.00	4.82	6.52	6.15	3.64
TSO B	Entry B1	2.71	2.71	4.82	5.12	3.67	2.29
	Exit Dom. B2	2.71	2.38	4.82	3.32	3.67	9.17
	Exit B3	2.71	2.82	N/A	N/A	N/A	N/A

Table 53: Summary of tariffs in all configurations

As a final remark, it is necessary to be aware that the outcome of a merger within a MS is that some points disappear, prompting the need for a reallocation of costs and revenues to the remaining points. This effect is similar to the one obtained by a potential European-wide removal of IPs as commercial points.

Annex H

Article 12(3) – Example of Fixed Payable Price (Binding beyond the Subsequent Gas Year) and Floating Payable Price

FIXED PAYABLE PRICE

A TSO is regulated under the price cap regime. The tariff period matches the gas year. Fixed payable price approach is offered for the reserve price for the yearly standard capacity product. In June (30 days before the July auction), the TSO publishes binding tariffs for such products for the upcoming gas year from October Y to September Y+1.

In the July auction for gas year 1, Network User 1 buys yearly standard capacity product over 10 consecutive years starting from gas year 1. The payable price for all booked capacity products over the period of 10 years is the reserve price for yearly standard capacity product published in the price decision valid in gas year 1 and the indexation is applied on it. Further, the risk premium reflecting the benefits of certainty regarding the level of transmission tariff could be added on top, if decided by NRA. Also, the auction premium, if any, is added on top. (Please see table below, Network User 1)

In the July auction for gas year 2, Network User 2 buys yearly standard capacity product over 9 consecutive years, starting from gas year 2.

Again the payable price for all booked capacity products over the period of 9 years is the reserve price for yearly standard capacity product published in the price decision valid in gas year 2 and the indexation is applied on it. Further, the risk premium reflecting the benefits of certainty regarding the level of transmission tariff could be added on top, if decided by NRA. Also, the auction premium, if any, is added on top. (Please see table below, Network User 2)

The fixed payable price in each year is calculated according to the formula set in Article 24 (b) of TAR NC.

$$P_{fix} = (P_{Ry} \times IND) + RP + AP$$

Where:

P_{fix} is the fixed payable price;

$P_{r,y}$ is the applicable reserve price for a yearly standard capacity product which is published at the time when this product is auctioned;

IND is the ratio between the chosen index at the time of use and the same index at the time the product was auctioned;

RP is the risk premium reflecting the benefits of certainty regarding the level of transmission tariff, where such premium shall be no less than 0;

AP is the auction premium, if any.

In the tables below, Pcl is the clearing price. Note: E.g. the consumer price index, the producer price index or their combinations can be used.

NETWORK USER 1										
Year	1	2	3	4	5	6	7	8	9	10
$P_{R,y}$	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Index*	100.00	101.30	102.72	104.36	105.82	107.09	108.59	110.11	111.87	113.38
IND	1.00	1.01	1.03	1.04	1.06	1.07	1.09	1.10	1.12	1.13
$P_{R,y}$ after IND	1.00	1.01	1.03	1.04	1.06	1.07	1.09	1.10	1.12	1.13
RP	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
AP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P_{cl}	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
P_{fix}	**1.20**	**1.21**	**1.23**	**1.24**	**1.26**	**1.27**	**1.29**	**1.30**	**1.32**	**1.33**
Δ	0.20	0.21	0.23	0.24	0.26	0.27	0.29	0.30	0.32	0.33

Table 54: Network user 1 – fixed payable price

NETWORK USER 2										
Year	1	2	3	4	5	6	7	8	9	10
$P_{R,y}$	1.00	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Index*	100.00	101.30	102.72	104.36	105.82	107.09	108.59	110.11	111.87	113.38
IND	X	1.00	1.01	1.03	1.04	1.06	1.07	1.09	1.10	1.12
$P_{R,y}$ after IND	x	1.50	1.52	1.55	1.57	1.59	1.61	1.63	1.66	1.68
RP	x	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
AP	x	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P_{cl}	x	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
P_{fix}	**x**	**1.70**	**1.72**	**1.75**	**1.77**	**1.79**	**1.81**	**1.83**	**1.86**	**1.88**
Δ	x	0.20	0.22	0.25	0.27	0.29	0.31	0.33	0.36	0.38

Table 55: Network user 2 – fixed payable price

Conclusion: the table below shows the difference between what Network User 1 and Network User 2 will pay for the same yearly standard capacity product. The price for Network User 2 is higher than for Network User 1 in the corresponding years as the reserve price was booked a year later. The reserve price had increased in that year, which increases the binding reserve price for all the subsequent years the capacity is booked for.

NETWORK USER 1 AND 2 COMPARISON										
Year	1	2	3	4	5	6	7	8	9	10
P_{fix} Net. User 1	1.20	1.21	1.23	1.24	1.26	1.27	1.29	1.30	1.32	1.33
P_{fix} Net. User 2	x	1.70	1.72	1.75	1.77	1.79	1.81	1.83	1.86	1.88

Table 56: Network user 1 and 2 comparison – fixed payable price

FLOATING PAYABLE PRICE

A TSO is regulated under the price cap regime. The tariff period matches the gas year. Only floating payable price is applied. In June (30 days before the July auction), the TSO publishes binding tariffs for the yearly standard capacity products for the upcoming gas year from October Y to September Y+1.

In the July auction for gas year 1, Network User 3 buys yearly standard capacity product over 10 consecutive years, starting from gas year 1. The payable price for capacity in gas year 1 is the reserve price for yearly standard capacity product published in the price decision valid in gas year 1. For capacity in gas year 2, the payable price is the reserve price for yearly standard capacity product published in the price decision valid in gas year 2 and so on. Further, the auction premium, if any, is added on top. (Please see table below, Network User 3)

In the July auction for gas year 2, Network User 4 buys yearly standard capacity product over 9 consecutive years, starting from gas year 2. The payable price for capacity in gas year 2 is the reserve price for yearly standard capacity product published in the price decision valid in gas year 2. For capacity in gas year 3, the payable price is the reserve price for yearly standard capacity product published in the price decision valid in gas year 3 and so on. Further, the auction premium, if any, is added on top. (Please see table below, Network User 4)

The floating payable price in each year is calculated according to the formula set in Article 24 (a) of TAR NC.

$$P_{flo} = P_{r,flo} + AP$$

Where:

P_{flo} is the floating payable price;

$P_{r,flo}$ is the reserve price for a standard capacity product applicable at the time when this product may be used;

AP is the auction premium, if any.

In the tables below, P_{cl} is the clearing price.

Conclusion: under the floating payable price approach, where capacity is bought for a gas year beyond the next, the reserve price will only be known before the yearly capacity auction that takes place prior to the respective gas year. The clearing price for future gas years only reflects an indicative reserve price. As can be seen from the tables below, the floating payable price for both Network User 3 and 4 will be the same for corresponding years, even though Network User 2 bought its standard capacity a year later.

NETWORK USER 3										
Gas year	1	2	3	4	5	6	7	8	9	10
$P_{R,flo}$	1.00	1.10	1.20	1.30	1.30	1.40	1.50	1.50	1.60	1.50
AP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P_{cl}	1.00	1.10	1.20	1.30	1.30	1.40	1.50	1.50	1.60	1.50
P_{flo}	**1.00**	**1.10**	**1.20**	**1.30**	**1.30**	**1.40**	**1.50**	**1.50**	**1.60**	**1.50**

Table 57: Network user 3 – floating payable price

NETWORK USER 4										
Gas year	1	2	3	4	5	6	7	8	9	10
$P_{R,flo}$	x	1.10	1.20	1.30	1.30	1.40	1.50	1.50	1.60	1.50
AP	x	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P_{cl}	x	1.10	1.20	1.30	1.30	1.40	1.50	1.50	1.60	1.50
P_{flo}	**x**	**1.10**	**1.20**	**1.30**	**1.30**	**1.40**	**1.50**	**1.50**	**1.60**	**1.50**

Table 58: Network user 4 – floating payable price

Image courtesy of Gascade

Annex I

Article 13 – Impact of Multipliers on the Reference Price for Non-Price Cap Regimes

The example shows the impact of a multiplier on the revenue recovery for one year. The example is based on the following inputs:

- Allowed revenue = 3,000 €;
- Forecasted contracted capacity = 250 MWh/day;
- Yearly reserve price = 12 $€/(\frac{MWh}{day})/year$;

Four scenarios with different Multipliers (M) and seasonal factors: The level of contracted capacity over the year (which is contracted with yearly, quarterly, monthly and daily bookings[1]) can be found in Figure 65.

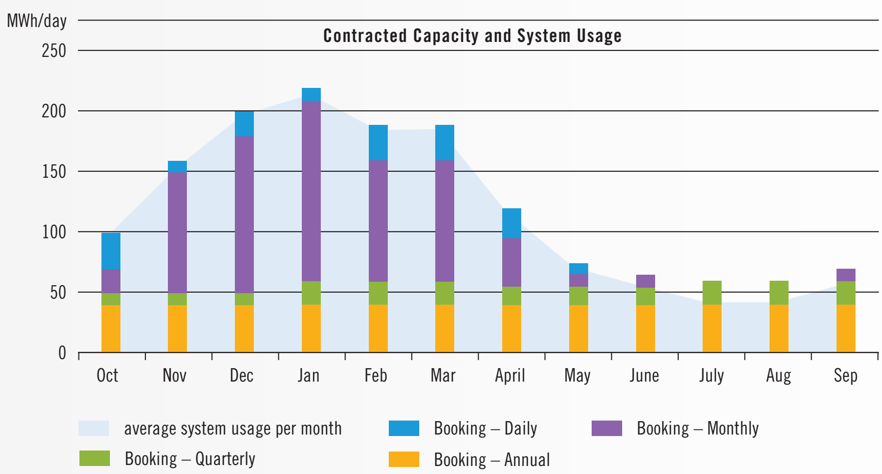


Figure 65: Contracted capacity and system usage in example of impact of low multipliers on yearly tariff

Usually, such a non-yearly booking is hard to forecast, because it depends on weather and market conditions. One way to limit the risk of under- or over-recovery is to introduce multipliers for non-yearly bookings, which are an incentive for shippers to book long-term. At the same time, multipliers and seasonal factors can limit a tariff increase, which is needed to meet the revenue cap. In the example, the non-yearly bookings were perfectly forecasted. This is to show only the effect of multipliers on the tariff, which is a simple postage stamp in the example.

1) The figures of daily contracted capacity in the table represent the average of daily bookings over each respective month.

Given these inputs, the increase of the tariff has been calculated for different scenarios:

1. **M = 1** for all non-yearly (quarterly, monthly, daily) standard capacity products; no seasonal factors
2. **M = 1** for all non-yearly standard capacity products; with seasonal factors
3. **M = 1.5** for all non-yearly standard capacity products; no seasonal factors
4. **M = 1.5** for all non-yearly standard capacity products; with seasonal factors

When seasonal factors have been used for the calculations, those have been calculated following the methodology described in the TAR NC, using a power of 1 for Article 15(3)(e). In the Table 19, the actual bookings as well as the partly applied seasonal factors can be found.

FORECASTED CONTRACTED CAPACITY

Month	Forecasted contracted capacity					seasonal factor
	yearly	quarterly	monthly	daily	sum	
Oct	40	10	20	30	100	0.79
Nov	40	10	100	10	160	1.27
Dec	40	10	130	20	200	1.59
Jan	40	20	150	10	220	1.75
Feb	40	20	100	30	190	1.51
Mar	40	20	100	30	190	1.51
Apr	40	15	40	25	120	0.95
May	40	15	10	10	75	0.60
Jun	40	15	10	0	65	0.52
Jul	40	20	0	0	60	0.48
Aug	40	20	0	0	60	0.48
Sep	40	20	10	0	70	0.56

Table 59: Forecasted contracted capacity and seasonal factor in example

The calculation of tariffs T follows a very simple approach using the Annual average of adjusted forecasted contracted capacity (AAAFCC):

$$T = Revenues / AAAFCC$$

The adjustments of the Forecasted contracted capacities are necessary to exactly meet the revenue cap due to the multipliers. The AAFCC is calculated as following:

$$AAAFCC = \frac{\sum_{m=1}^{12} M \times SF_m \times short - term - capacity_m \times days_m}{365\ days}$$

In Table 60, the AAAFCC as well as the tariffs in the four described scenarios can be found.

CALCULATION OF TARIFFS					
	M	Seasonal factors	AAAFCC	Tariff	Tariff reduction compared to Scenario 1
Scenario 1	1	No	125.55	23.90	0 %
Scenario 2	1	Yes	153.62	19.53	–18 %
Scenario 3	1.5	No	168.32	17.82	–25 %
Scenario 4	1.5	Yes	210.43	14.26	–40 %

Table 60: Calculation of tariffs and comparison of these in the example

Higher values of multipliers, as well as seasonal factors can limit the tariffs level. Any increase of the yearly tariff would have an impact on network users. Low multipliers lead to higher tariffs. Therefore, the burden for those network users who are not able to book non-yearly products due to a flat usage over the year, e. g. industrial customers, would be higher with lower multipliers.

Annex J

Article 14 – Example of Calculating Reserve Prices for Firm Non-Yearly Capacity Products without Seasonal Factors

1 Example of pricing for a quarterly product:

How much does it cost to book quarterly capacity from October to December if the annual tariff is 1 €/(kWh/h)/year and the corresponding quarterly multiplier is 1.4?

$$P_{st} = m \times (p_y/365) \times d$$

$$P_{st} = 1.4 \times (1/365) \times 92$$

Quarterly price = 0.3529 €/(kWh/h) (↔ the capacity to flow 1 kWh every hour of the considered fourth quarter costs a total of 0.3529 €)

2 Example of pricing for a monthly product:

How much does it cost to book monthly capacity for July if the annual tariff is 1 €/(kWh/h)/year and the corresponding monthly multiplier is 1?

$$P_{st} = m \times (p_y/365) \times d$$

$$P_{st} = 1 \times (1/365) \times 31$$

Monthly price = 0.0849 €/(kWh/h) (↔ the capacity to flow 1 kWh every hour of the considered month of July costs a total of 0.0849 €)

3 Example of pricing for a daily product:

How much does it cost to book daily capacity for February if the annual tariff is 1 € (kWh/h)/year and the daily multiplier is 1.3?

$$P_{st} = m \times (p_y/365) \times d$$

$$P_{st} = 1.3 \times (1/365) \times 1$$

Daily price = 0.0036 €/(kWh/h) (↔ the capacity to flow 1 kWh every hour of the considered day of February costs a total of 0.0036 €)

4 Example of pricing for a within-day product:

How much does it cost to book within-day capacity (rest of the day = 18 hours) for March if the annual tariff is 1 €/(kWh/h)/year and the within-day multiplier is 1.5?

$$P_{st} = m \times (p_y/8760) \times h$$

$$P_{st} = 1.5 \times (1/8760) \times 18$$

Within-day price = 0.0031 €/(kWh/h) (↔ the capacity to flow 1 kWh every hour of the remaining 18 hours of the considered day of March costs a total of 0.0031 €)

Annex K

Article 15(1) – Example of Calculating Reserve Prices for Non-Yearly Firm Capacity Products with Seasonal Factors

1 Example of pricing for a quarterly product:

How much does it cost to book quarterly capacity from January to March if the annual tariff is 1 €/(kWh/h)/year, the corresponding quarterly multiplier is 1.5 and the corresponding seasonal factor for the months of January, February and March is 1.25?

$$P_{st} = m \times sf \times (p_y/365) \times d$$

$$P_{st} = 1.5 \times 1.25 \times (1/365) \times 90$$

Quarterly price = 0.4623 €/(kWh/h)(⟷ the capacity to flow 1 kWh every hour of the considered first quarter costs a total of 0.4623 €)

2 Example of pricing for a monthly product:

How much does it cost to book monthly capacity for June if the annual tariff is 1 €/(kWh/h), the corresponding monthly multiplier is 1 and the corresponding seasonal factor for the month of June is 0.7?

$$P_{st} = m \times sf \times (p_y/365) \times d$$

$$P_{st} = 1 \times 0.7 \times (1/365) \times 30$$

Monthly price = 0.0575 €/(kWh/h) (⟷ the capacity to flow 1 kWh every hour of the considered month of June costs a total of 0.0575 €)

3 Example of pricing for a daily product:

How much does it cost to book daily capacity for April if the annual tariff is 1 €/(kWh/h), the corresponding daily multiplier is 1 and the corresponding seasonal factor for the month of April is 1.1?

$$P_{st} = m \times sf \times (p_y/365) \times d$$

$$P_{st} = 1 \times 1.1 \times (1/365) \times 1$$

Daily price = 0.0030 €/(kWh/h) (⟷ the capacity to flow 1 kWh every hour of the considered day of April costs a total of 0.0030 €)

4 Example of pricing for a within-day product:

How much does it cost to book within-day capacity (rest of the day = 5 hours) for September if the annual tariff is 1 €/(kWh/h), the corresponding within-day multiplier is 0.9 and the corresponding seasonal factor for the month of September is 1.3?

$$P_{st} = m \times sf \times (p_y/8760) \times h$$

$$P_{st} = 0.9 \times 1.3 \times (1/8760) \times 5$$

Within-day price = 0.0007 €/(kWh/h) (⟷ the capacity to flow 1 kWh every hour of the remaining 5 hours of the considered day of September costs a total of 0.0007 €)

Annex L

Article 15 – Seasonal Factors Methodology

For monthly standard capacity products:

Seasonal factors for monthly products are calculated using as an input the forecasted flows for each month. Only if the forecasted flows for one month (or more) are 0, forecasted contracted capacity should be used in the calculations.

(a) For each of the months, calculate the forecasted flows or forecasted contracted capacity.

$$Month_i \rightarrow Flows_i$$

(b) For each of the months, calculate the usage rate for each month:

$$Usage\ rate_i = \frac{Flows_i}{\sum_{i=1}^{12} Flows_i}$$

(c) For each of the months, calculate the primary factor:

$$Primary\ factor_i = Usage\ rate_i \times 12$$

* If one of the above calculated primary factors is equal to 0, then this value needs to be corrected. Its value will be changed to whichever is lower: (1) the lowest of the other primary factors; or (2) 0.1.

(d) For each of the months, calculate the initial level of the seasonal factors:

$$Initial\ SF_{monthly,i} = Primary\ factor_i^{\ s}$$

* The parameter s is applied in order to penalise/incentivise more clearly the months that deviate the most from a flat usage. With $s = 1$, the seasonal factors are directly proportional to the use for the system. With $0 \leq s < 1$, seasonal factors would be 'softened' and can be utilised for cases where flow changes are extreme between the different periods. With $1 < s \leq 2$, seasonal factors increase/decrease in an exponential way as shown in Figure 66:

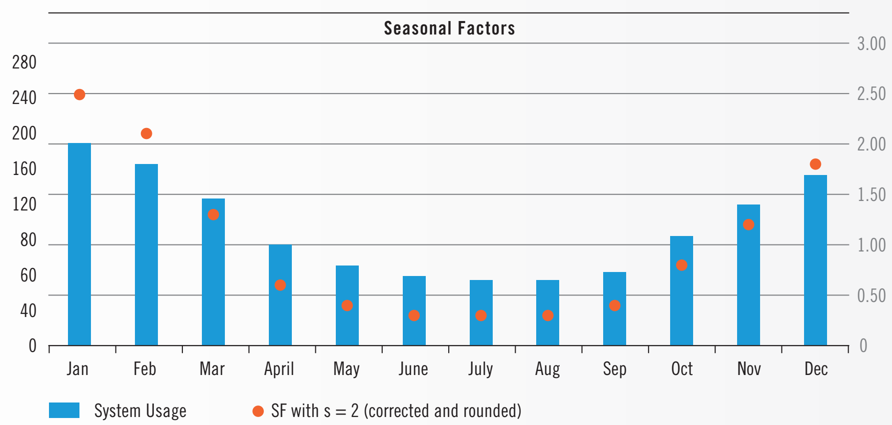


Figure 66: Seasonal factors and power factor

(e) Calculate the average over the year for the product of multiplier and seasonal factor. This is to check if it is equal to or higher than 1 and equal to or lower than 1.5.

$$Average = \frac{\sum_{i=1}^{12} M_{monthly} \times Initial\ SF_{monthly,i}}{12}$$

(f) If the value of the average falls within the range from 1 to 1.5, there is no correction step needed. If the average is lower than 1 or higher than 1.5, the following correction step is needed:

If $1 \leq Average \leq 1.5$, then: $SF_{monthly,i} = Initial\ SF_{monthly,i}$

If $Average < 1$, then: $SF_i = Initial\ SF_{monthly,i} \times \frac{1}{Average}$

If $Average > 1.5$, then: $SF_i = Initial\ SF_{monthly,i} \times \frac{1.5}{Average}$

For daily and within-day standard capacity products

Seasonal factors for daily and within-day products are calculated on the basis of the initial seasonal factors for monthly standard capacity products, applying the steps (e) and (f) above taking into account the corresponding multipliers. Thus, initial seasonal factors for daily standard capacity products mentioned in the formula below are in fact the initial seasonal factors for monthly standard capacity products.

$$Average = \frac{\sum_{i=1}^{12} M_{daily} \times Initial\ SF_{daily,i}}{12}$$

If the value of the average falls within the range from 1 to 3, there is no correction step needed. If the average is lower than 1 or higher than 3, the following correction step is needed:

If $1 \leq Average \leq 3$, then: $SF_{daily,i} = Initial\ SF_{daily,i}$

If $Average < 1$, then: $SF_i = Initial\ SF_{daily,i} \times \frac{1}{Average}$

If $Average > 3$, then: $SF_i = Initial\ SF_{daily,i} \times \frac{3}{Average}$

For daily and within-day products, the correction step in points (f) to (h) must be applied 'mutatis mutandis', meaning that:

- By default, the cap of 1.5 will be changed to the cap of 3;
- In duly justified cases, the cap of 1.5 will be changed to the respective applied multiplier cap (more than 3) and the floor of 1 will be changed to the respective applied multiplier floor (more than 0 and less than 1).

For quarterly standard capacity products

Seasonal factors for quarterly products are calculated as follows:

(a) Calculate the initial level of the seasonal factors by one of the following alternatives:

Option 1: $Initial\ SF_{quarterly,i} = \frac{\sum_{i=1}^{3} SF_{monthly,i}}{3}$

Option 2: $Initial\ SF_{quarterly,i}$ is equal to any value within the minimum and maximum corresponding seasonal factors of the quarter.

(b) Apply the steps (e) and (f) above as set out for monthly seasonal factors taking into account the quarterly multiplier.

$$Average = \frac{\sum_{i=1}^{4} M_{quarterly} \times Initial\ SF_{quarterly,i}}{4}$$

If $1 \leq Average \leq 1.5$, then: $SF_{quarterly,i} = Initial\ SF_{quarterly,i}$

If $Average < 1$, then: $SF_i = Initial\ SF_{quarterly,i} \times \frac{1}{Average}$

If $Average > 1.5$, then: $SF_i = Initial\ SF_{quarterly,i} \times \frac{1.5}{Average}$

Annex M

Article 15 – Example of Calculating Seasonal Factors

This example will follow the lettering sequence as set out in the Article 15(3) of the TAR NC, be based on forecasted flows and the following parameters:

PARAMETERS USED					
	quarterly	monthly	daily/within-day	Power	correction factor
Multiplier	1.1	1.4	3	2	**0.946132187**
Limit	1.5	1.5	3	2	**0.883056708**

Table 61: Parameters used for calculating the seasonal factors[1)]

These calculations derive the monthly and daily/within-day Seasonal Factors (tables F and H Monthly and Daily/Within-day), which after correction are both within ranges defined as per the TAR NC. The figure below represents the forecasted flows and the calculated seasonal factors.

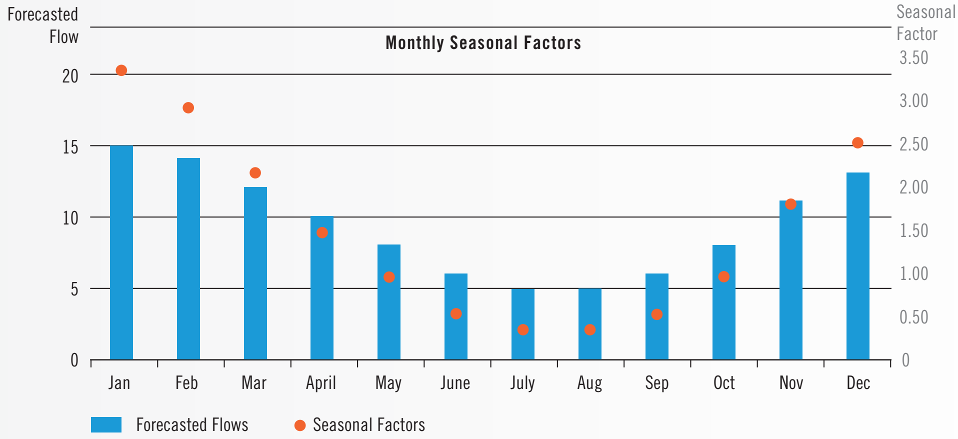


Figure 67: Forecasted flows and calculated monthly seasonal factors

Table 62 shows the sequence of steps to calculate the Seasonal Factors.

1) in this example, the correction factor for monthly products is calculated as the ratio between 1.5 in step for Article 15(3)(h) (line 'Average') and 1.58… for Article 15(3)(f) (line 'Average'). The correction factor for daily/within-day products is calculated as the ratio between 3 in step for Article 15(3)(h) (line 'Average') and 3.39… for Article 15(3)(f) (line 'Average').

SEQUENCE OF STEPS

15(3)a Forecasted flows		15(3)b Sum of Monthly Forecasted Flows	15(3)c Usage rate: Monthly flows divided by Sum	15(3)d Preceding (c) values multiplied by 12	15(3)e Preceding (d) values raised to the power of 2
Jan	15	113	0,132743363	1,592920354	2,537395254
Feb	14	113	0,123893805	1,486725664	2,210353199
Mar	12	113	0,10619469	1,274336283	1,623932963
Apr	10	113	0,088495575	1,061946903	1,127731224
May	8	113	0,07079646	0,849557522	0,721747983
Jun	6	113	0,053097345	0,637168142	0,405983241
Jul	5	113	0,044247788	0,530973451	0,281932806
Aug	5	113	0,044247788	0,530973451	0,281932806
Sep	6	113	0,053097345	0,637168142	0,405983241
Oct	8	113	0,07079646	0,849557522	0,721747983
Nov	11	113	0,097345133	1,168141593	1,364554781
Dec	13	113	0,115044248	1,380530973	1,905865769
Sum:	**113**				

MONTHLY SF

	15(3)f Monthly SF: preceding (e) values multiplied by the Multiplier	15(3)h Monthly SF: preceding (f) values multiplied by correction factor
Jan	3,552353356	3,360995851
Feb	3,094494479	2,92780083
Mar	2,273506148	2,151037344
Apr	1,578823714	1,493775934
May	1,010447177	0,956016598
Jun	0,568376537	0,537759336
Jul	0,394705928	0,373443983
Aug	0,394705928	0,373443983
Sep	0,568376537	0,537759336
Oct	1,010447177	0,956016598
Nov	1,910376694	1,80746888
Dec	2,668212076	2,524481328
Average	**1,585402146**	**1,5**

DAILY/WITHIN DAY SF

15(3)f Daily/Within-day SF: preceding (e) values multiplied by the multiplier	15(3)h Daily/Within-day SF: preceding (f) values multiplied by correction factor
7,612185762	6,721991701
6,631059597	5,85560166
4,871798888	4,302074689
3,383193672	2,987551867
2,16524395	1,912033195
1,217949722	1,075518672
0,845798418	0,746887967
0,845798418	0,746887967
1,217949722	1,075518672
2,16524395	1,912033195
4,093664343	3,614937759
5,717597306	5,048962656
3,397290312	**3**

Table 62: Sequence of steps taken to calculate the seasonal factors

Annex N

Article 16 – Example of Calculating Discounts for Interruptible Capacity Products

EX-ANTE DISCOUNT

Example: Calculation of ex-ante discount for monthly standard capacity product for interruptible capacity, based on the formula:

$$Di_{ex\text{-}ante} = Pro \times A \times 100\%$$

The Pro factor is calculated as set out in Article 16(3) according to the following parameter.

PARAMETERS USED TO CALCULATE THE PRO FACTOR	
Expectation of the number of interruptions over D	N = 5
Average duration of the expected interruptions expressed in hours	D_{int} = 12 hours
Total duration of monthly standard capacity product for interruptible capacity in hours	D = 744 hours
Expected average amount of the interrupted capacity for each interruption related to monthly standard capacity product for interruptible capacity	$CAP_{av.int}$ = 150,000 kWh/h
Total amount of interruptible capacity for the respective type of standard capacity product for interruptible capacity	CAP = 10,000,000 kWh/h
'A' factor	A = 100

Table 63: Parameters used to calculate the Pro factor

$$\text{Pro} = \frac{5 \times 12}{744} \times \frac{150{,}000}{10{,}000{,}000} = 0.00121$$

$$\text{Di}_{\text{ex-ante}} = Pro \times 100 \times 100\% = 12.1\%$$

INTERRUPTIBLE RESERVE PRICE

Example: Calculation of reserve price for monthly standard capacity product for interruptible capacity in accordance with Article 16(1):

$$P_{INT} = (100\% - Di_{ex-ante}) \times ((M \times S \times T / 365) \times D)$$

The discounted reserve price for a standard capacity product for interruptible capacity is calculated by the actual reserve price as set out in Article 14 or 15 combined with the ex-ante discount as described in the previous section. Following parameters are used in this example.

PARAMETERS USED TO CALCULATE THE EX-ANTE DISCOUNT	
Ex-ante discount	$Di_{ex\text{-}ante}$ = 12.1 %
Multiplier for monthly standard capacity product (no seasonal factor, i. e. S=1)	Mm = 1.5
Reference price	T = 1 €/(kWh/h)/year
Duration of the monthly standard capacity product expressed in gas days	D = 31

Table 64: Parameters used to calculate the ex-ante discount

$$P_{int} = (1 - 0.121) \times (1.5 \times \frac{1}{365}) \times 31 = \ 0.1127\ €/(\frac{kWh}{h})/\text{month}$$

EX-POST COMPENSATION

Example: Calculation of ex-post compensation for interruption of daily and within-day standard capacity product for interruptible capacity. As set out in Article 16(4), the ex-post compensation must reimburse to the network user **three times the price of the daily standard capacity product** for each day an interruption occurred.

The formula below is not set out in the TAR NC and is constructed per ENTSOG's assumption that it could take account of the amount of interrupted capacity.

Example for a daily interruption

Ex-post compensation = 3 × (M × S × T/365) × (I × D)

Where:

M is the level of the multiplier corresponding to the daily standard firm capacity product;

S is the level of seasonal factor corresponding to the daily standard firm capacity product, if any;

T is the reserve price for yearly firm capacity product;

D is the duration of interruption for the daily standard firm capacity product expressed in gas days;

For leap years, the formula shall be adjusted so that the figure 365 is substituted with the figure 366;

I is the amount of interrupted capacity.

PARAMETERS USED TO CALCULATE THE EX-POST DISCOUNT FOR A DAILY INTERRUPTION	
Multiplier for daily standard capacity product	M = 2
Reference price	T = 1 €/(kWh/d)/year
Number of Days on which an interruption occurred	D = 5 d
Interrupted capacity	I = 1,000 kWh/d

Table 65: Parameters used to calculate the ex-post discount for a daily interruption

$$ex\ post\ compensation = 3 \times 2 \times \frac{1}{365} \times 5 \times 1000 = \ 82{,}20\ €$$

Example for a within day interruption

$$\text{Ex-post compensation} = 3 \times (M \times S \times T/365) \times (I \times D/24)$$

Where:

M is the level of the multiplier corresponding to the daily standard firm capacity product;

S is the level of seasonal factor corresponding to the daily standard firm capacity product, if any;

T is the reserve price for yearly firm capacity product;

D is the number of interrupted hours;

D/24 represents the proportion of the gas day for which the capacity was interrupted**;**

For leap years, the formula shall be adjusted so that the figure 365 is substituted with the figure 366;

I is the amount of interrupted capacity.

PARAMETERS USED TO CALCULATE THE EX-POST DISCOUNT FOR A WITHIN-DAY INTERRUPTION	
Multiplier for daily standard capacity product	M = 2
Reference price	T = 1 €/(kWh/h)/year
Number of hours on which an interruption occurred	D = 5 h
Interrupted capacity	I = 1,000 kWh/h

Table 66: Parameters used to calculate the ex-post discount for a within-day interruption

$$ex\ post\ compensation = 3 \times 2 \times \frac{1}{365} \times \frac{5}{24} \times 1000 = 3{,}42\ €$$

Annex O

Article 29(b)(ii) – Example of the Probability of Interruption Assessment

The three tables below represent, respectively, a proposal for the format of data publication for an assessment of the probability of interruption as set out in Article 29(b)(ii) of the TAR NC and examples of how to group the information regarding different interruptible capacity products.

PROPOSAL FOR THE FORMAT OF DATA PUBLICATION			
	Year concerned – IP identification, product duration		
	Type 1	**Type 2**	**Type n**
Explanation of the calculation of the probability of interruption			
Explanation of the historical and/or forecasted data used to estimate the probability of interruption			
Probability of interruption ('Pro')			
Data used for the estimation of the probability of interruption			
Value of the adjustment factor ('A')			
Ex-ante Discount ($Di\_(_{ex\text{-}ante})$)			
Ex-post Discount ('Yes' or 'n/a'; if 'Yes' then explain how the conditions were met)			

Table 67: Proposal for the format of data publication for an assessment of the probability of interruption

EXAMPLE 1 FOR CLASSIFICATION OF INTERRUPTIBLE CAPACITY PRODUCTS		
	October 2017 – September 2018 – IP 1	
	IP 1 – entry	**IP 1 – exit**
Explanation of the probability of interruption	Interruption if domestic consumption is low	Interruption if domestic consumption is high
Explanation of the historical and/or forecasted data used to estimate the probability of interruption	Use of historical probability (2010 to 2015)	Use of historical probability (2010 to 2015)
Probability of interruption ('Pro')	0.25	0.05
Data used for the estimation of the risk of interruption	Data sheet to be included	Data sheet to be included
Value of the adjustment factor 'A'	2	5
Ex-ante Discount ($Di\_(_{ex\text{-}ante})$)	50 %	25 %
Ex-post Discount ('Yes' or 'n/a'; if 'Yes' then explain how the conditions were met)	n/a	n/a

Table 68: Example 1 for classification of interruptible capacity products

EXAMPLE 2 FOR CLASSIFICATION OF INTERRUPTIBLE CAPACITY PRODUCTS		
	October 2017 – September 2018 – IP 2	
	IP 2 – entry	**IP 2 – exit**
Explanation of the probability of interruption	Interruption if counter-flow is too high	Interruption due to the utilisation of the neighbouring infrastructure operator
Explanation of the historical and/or forecasted data used to estimate the probability of interruption	Forecasted probability based on trend in probability since 2015	n/a
Probability of interruption ('Pro')	0.1	n/a
Data used for the estimation of the risk of interruption	Data sheet to be included	n/a
Value of the adjustment factor 'A'	1	n/a
Ex-ante Discount (Di_$_{(ex\text{-}ante)}$)	10%	n/a
Ex-post Discount ('Yes' or 'n/a'; if 'Yes' then explain how the conditions were met)	n/a	Yes; the conditions are met as there was no interruption due to physical congestion in the year October 2015–September 2016

Table 69: Example 2 for classification of interruptible capacity products

Image courtesy of ONTRAS

Annex P

Article 30(2)(b) – Example of a Simplified Tariff Model

The simplified tariff model presented in this example is designed for a system in which the postage stamp RPM is used. It is supposed to enable network users to forecast future tariffs for different capacity products by creating their own capacity forecast.

Since there is no distinction between entry and exit tariffs, the assumption is that the entry-exit split results from the forecasted contracted capacity. Within-day products are not being considered by the model. The discount for interruptible capacity products is considered to be 10 %. The multipliers are 1.4 (daily capacity product), 1.25 (monthly capacity product) and 1.1 (quarterly capacity product).

The colour code is:

- Cells in red have to be filled out by the network user.
- Cells in orange may be given by the TSO but can be modified or be filled out by the network user.
- Cells in blue are calculated automatically.

The logic of using the model is as follows:

- The input given by the TSO in this example are the allowed revenue projections in row 3 and the expected capacity sales for the upcoming year in cells C7–C26.
- In cells C32–C50, the amount of non-yearly capacity is adjusted by multipliers, duration of capacity products and applied discounts. In that way, all forecasted capacity sales for all capacity products are 'standardised' to the yearly firm freely allocable capacity product so that there is a yearly equivalent of non-yearly capacity sales. For example, for quarterly firm freely allocable capacity product the following calculation is done: the forecast of capacity sales is multiplied by the product duration and the respective multiplier and then, divided by 365 being the number of days in a year.
- Dividing the allowed revenue (C3) by the sum of the standardised forecasted capacity sales (C31–C50) results in the reference price for the yearly firm freely allocable capacity product.
- Beginning at the reference price, in cells C58–C77, the reserve prices for all other capacity products with different duration are being calculated.

The example given in this Annex on the next double page is only one possible way how to design a simplified tariff model. In practice it depends on the applied RPM and system characteristics.

SIMPLIFIED TARIFF MODEL FOR POSTAGE STAMP RPM

A/1	B	C	D	E	F	G	H
2							
3			2018	2019	2020	2021	2022
4		**Allowed revenue (Projection) in €**	100,000,000	102,000,000	105,000,000	107,000,000	112,000,000
5	1.	**Forecast of capacity sales**					
6							
7		**Firm freely allocable capacity**					
8		yearly	1,000				
9		quarterly (90 days)	3,000				
10		quarterly (91 days)	2,000				
11		quarterly (92 days)	5,000				
12		monthly (28 days)	1,000				
13		monthly (29 days)	0				
14		monthly (30 days)	4,000				
15		monthly (31 days)	7,000				
16		daily	200,000				
17							
18		**Interruptible freely allocable capacity**					
19		yearly	500				
20		quarterly (90 days)	1,500				
21		quarterly (91 days)	1,000				
22		quarterly (92 days)	2,500				
23		monthly (28 days)	500				
24		monthly (29 days)	0				
25		monthly (30 days)	2,000				
26		monthly (31 days)	3,500				
27		daily	100,000				
28							
29	2	**Multiplier, product duration, product discount**					
30		**Firm freely allocable capacity**					
31		yearly (1)	1,000	0.00	0.00	0.00	0.00
32		quarterly (90 days)	814	0.00	0.00	0.00	0.00
33		quarterly (91 days)	548	0.00	0.00	0.00	0.00
34		quarterly (92 days)	1,386	0.00	0.00	0.00	0.00
35		monthly (28 days)	96	0.00	0.00	0.00	0.00
36		monthly (29 days)	0	0.00	0.00	0.00	0.00
37		monthly (30 days)	411	0.00	0.00	0.00	0.00
38		monthly (31 days)	743	0.00	0.00	0.00	0.00
39		daily	767	0.00	0.00	0.00	0.00
40							
41		**Interruptible freely allocable capacity**					
42		yearly (1)	450	0.00	0.00	0.00	0.00
43		quarterly (90 days)	366	0.00	0.00	0.00	0.00
44		quarterly (91 days)	247	0.00	0.00	0.00	0.00
45		quarterly (92 days)	624	0.00	0.00	0.00	0.00
46		monthly (28 days)	43	0.00	0.00	0.00	0.00
47		monthly (29 days)	0	0.00	0.00	0.00	0.00
48		monthly (30 days)	185	0.00	0.00	0.00	0.00
49		monthly (31 days)	334	0.00	0.00	0.00	0.00
50		daily	345	0.00	0.00	0.00	0.00
51							
52		**Sum of firm freely allocable contracted capacity**	8,360	0.00	0.00	0.00	0.00
53		**Reference price (yearly firm freely allocable) in €**	11,962	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
54							

SIMPLIFIED TARIFF MODEL FOR POSTAGE STAMP RPM							
55	33	Reserve prices					
56		**Firm freely allocable capacity**					
57		yearly (1)	11,962				
58		quarterly (90 days)	3,244				
59		quarterly (91 days)	3,280				
60		quarterly (92 days)	3,316				
61		monthly (28 days)	1,147				
62		monthly (29 days)	1,188				
63		monthly (30 days)	1,229				
64		monthly (31 days)	1,270				
65		daily	46				
66							
67		**Interruptible freely allocable capacity**					
68		yearly (1)	10,765				
69		quarterly (90 days)	2,920				
70		quarterly (91 days)	2,952				
71		quarterly (92 days)	2,985				
72		monthly (28 days)	1,032				
73		monthly (29 days)	1,069				
74		monthly (30 days)	1,106				
75		monthly (31 days)	1,143				
76		daily	41				

Table 70: Example of a simplified tariff model

Annex Q

Article 31 – When to Publish What

The tables below outline the deadlines for publication of information directly/via a link on ENTSOG's Transparency Platform and on TSO/NRA website. Each table covers one 'cycle' of publication of information, i.e. both obligations: publication before the auctions and, for each tariff period, publication before the tariff period.

For the first iteration of the process, it would be necessary to publish the following information outlined in Table 71:

PUBLICATION OF INFORMATION ON TSO/NRA WEBSITE AND ENTSOG'S TP, 1ST ITERATION			
Tariff period	**When to publish**	**What to publish on TSO/NRA website**	**What to publish on ENTSOG's TP**
Jan 2018 – Dec 2018	Before tariff period: Dec 2017	◢ Set of info before the tariff period	◢ Link to the set of info before the tariff period ◢ In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2018	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2018–Dec 2018 (old tariffs) (2) Jan 2019–Sep 2019 (old tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Apr 2018 – Mar 2019	Before tariff period: Mar 2018	◢ Set of info before the tariff period	◢ Link to the set of info before the tariff period ◢ In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2018	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2018–Mar 2019 (old tariffs) (2) Apr 2019–Sep 2019 (old tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Jul 2018 – Jun 2019	Before tariff period and before auctions: Jun 2018	◢ Set of info before the tariff period ◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2018–Jun 2019 (old tariffs) (2) Jul 2019–Sep 2019 (old tariffs)	◢ Link to the set of info before the tariff period and before the auction ◢ In a standardised table, flow-based charge, simulation of all the costs for flowing 1 GWh/day/year and reserve prices at IPs
Oct 2018 – Sep 2019	Before tariff period: Sep 2018	◢ Set of info before the tariff period	◢ Link to the set of info before the tariff period ◢ In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2018	◢ Set of info before the auction, including binding reserve prices for: (1) Oct 2018–Sep 2019 (old tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Jan 2016 – Dec 2019	Before tariff period	n/a	n/a
	Before auctions: Jun 2018	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2018–Sep 2019 (old tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Jan 2017 – Dec 2020	Before tariff period	n/a	n/a
	Before auctions: Jun 2018	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2018–Sep 2019 (old tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs

Table 71: Publication of information on TSO/NRA website and ENTSOG's TP, 1st iteration

For the second iteration of the process, it would be necessary to publish the following information outlined in Table 72:

PUBLICATION OF INFORMATION ON TSO/NRA WEBSITE AND ENTSOG'S TP, 2ND ITERATION			
Tariff period	**When to publish**	**What to publish on TSO/NRA website**	**What to publish on ENTSOG's TP**
Jan 2019 – Dec 2019	Before tariff period: Dec 2018	◢ Set of info before the tariff period	◢ Link to the set of info before the tariff period ◢ In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2019	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2019–Dec 2019 (old tariffs) (2) Jan 2020–Sep 2020 (**new** tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Apr 2019 – Mar 2020	Before tariff period: Mar 2019	◢ Set of info before the tariff period	◢ Link to the set of info before the tariff period ◢ In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2019	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2019–Mar 2020 (old tariffs) (2) Apr 2020–Sep 2020 (**new** tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Jul 2019 – Jun 2020	Before tariff period and before auctions: Jun 2019	◢ Set of info before the tariff period ◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2019–Jun 2020 (**new** tariffs) (2) Jul 2020–Sep 2020 (**new** tariffs)	◢ Link to the set of info before the tariff period and before the auction ◢ In a standardised table, flow-based charge, simulation of all the costs for flowing 1 GWh/day/year and reserve prices at IPs
Oct 2019 – Sep 2020	Before tariff period: Sep 2019	◢ Set of info before the tariff period	◢ Link to the set of info before the tariff period ◢ In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2019	◢ Set of info before the auction, including binding reserve prices for: (1) Oct 2019–Sep 2020 (**new** tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Jan 2016 – Dec 2019	Before tariff period	n/a	n/a
	Before auctions: Jun 2019	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2019– Dec 2019 (old tariffs) (2) Jan 2020–Sep 2020 (**new** tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs
Jan 2017 – Dec 2020	Before tariff period	n/a	n/a
	Before auctions: Jun 2019	◢ Set of info before the auction, including separate binding reserve prices for: (1) Oct 2019– Sep 2020 (old tariffs)	◢ Link to the set of info before the auction ◢ In a standardised table, reserve prices at IPs

Table 72: Publication of information on TSO/NRA website and ENTSOG's TP, 2nd iteration

For the third iteration of the process, it would be necessary to publish the following information outlined in Table 73:

PUBLICATION OF INFORMATION ON TSO/NRA WEBSITE AND ENTSOG'S TP, 3RD ITERATION

Tariff period	When to publish	What to publish on TSO/NRA website	What to publish on ENTSOG's TP
Jan 2020 – Dec 2020	Before tariff period: Dec 2019	Set of info before the tariff period	Link to the set of info before the tariff period In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2020	Set of info before the auction, including separate binding reserve prices for: (1) Oct 2020–Dec 2020 (**new** tariffs) (2) Jan 2021–Sep 2021 (**new** tariffs)	Link to the set of info before the auction In a standardised table, reserve prices at IPs
Apr 2020 – Mar 2021	Before tariff period: Mar 2020	Set of info before the tariff period	Link to the set of info before the tariff period In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2020	Set of info before the auction, including separate binding reserve prices for: (1) Oct 2020–Mar 2021 (**new** tariffs) (2) Apr 2021–Sep 2021 (**new** tariffs)	Link to the set of info before the auction In a standardised table, reserve prices at IPs
Jul 2020 – Jun 2021	Before tariff period and before auctions: Jun 2020	Set of info before the tariff period Set of info before the auction, including separate binding reserve prices for: (1) Oct 2020–Jun 2021 (**new** tariffs) (2) Jul 2021–Sep 2021 (**new** tariffs)	Link to the set of info before the tariff period and before the auction In a standardised table, flow-based charge, simulation of all the costs for flowing 1 GWh/day/year and reserve prices at IPs
Oct 2020 – Sep 2021	Before tariff period: Sep 2020	Set of info before the tariff period	Link to the set of info before the tariff period In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2020	Set of info before the auction, including binding reserve prices for: (1) Oct 2020–Sep 2021 (**new** tariffs)	Link to the set of info before the auction In a standardised table, reserve prices at IPs
Jan 2020 – Dec 2023	Before tariff period: Dec 2019	Set of info before the tariff period	Link to the set of info before the tariff period In a standardised table, flow-based charge and simulation of all the costs for flowing 1 GWh/day/year
	Before auctions: Jun 2020	Set of info before the auction, including separate binding reserve prices for: (1) Oct 2020–Sep 2021 (**new** tariffs)	Link to the set of info before the auction In a standardised table, reserve prices at IPs
Jan 2017 – Dec 2020	Before tariff period	n/a	n/a
	Before auctions: Jun 2019	Set of info before the auction, including separate binding reserve prices for: (1) Oct 2020–Dec 2020 (old tariffs) (2) Jan 2021–Sep 2021 (**new** tariffs)	Link to the set of info before the auction In a standardised table, reserve prices at IPs

Table 73: Publication of information on TSO/NRA website and ENTSOG's TP, 3rd iteration

The third iteration of the process is when the 'new' tariffs are published throughout the EU before the annual yearly capacity auctions, except for the time period from October 2020 until December 2020 for one case where the tariff period is not equal to one year.

Annex R

Versions of ENTSOG's TAR NC and Additional Material

For all ENTSOG's documents listed in Table 74, please refer to ENTSOG's website: http://entsog.eu/publications/tariffs#All

VERSIONS OF ENTSOG'S TAR NC AND ADDITIONAL MATERIAL		
Date	**ENTSOG's version of the TAR NC**	**Version of Additional Document**
31 July 2015	Re-submitted TAR NC (TAR0500-15)	Explanatory Document (TAR0501-15)
26 December 2014	TAR NC for Reasoned Opinion (TAR0450-14)	Accompanying Document (TAR0451-14)
7 November 2014	Refined Draft TAR NC (TAR0350-14)	Analysis of Decisions Document (TAR0351-24)
30 May 2014	Initial Draft TAR NC (TAR200-14)	Supporting Document (TAR300-14)
Date	**Other material**	
30 January 2014	Final Project Plan for the TAR NC (TAR202-14)	
22 January 2014	Launch Documentation for the TAR NC (TAR136-13)	
Date	**Basis for ENTSOG's TAR NC development**	
19 December 2013	Invitation to Draft TAR NC (EC)	
29 November 2013	TAR FG (ACER)	

Table 74: Versions of ENTSOG's TAR NC and Additional Material

List of Figures

List of Tables

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators established by Regulation (EC) No 713/2009
AD	application date
Amended CAM NC	Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013, (OJ L 72, 17.3.2017, p. 1)
BAL NC	Commission Regulation No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks (OJ L 91, 27.3.2014, p. 15)
CAA	cost allocation assessments
CMP Guidelines	Chapter 2.2 of Annex I to Regulation (EC) No 715/2009
Comitology Procedure	regulatory procedure with scrutiny according to Article 5a(1) to (4) and Article 7 of Council Decision 1999/468/EC
CRRC	complementary revenue recovery charge
CWD	capacity weighted distance
EC	the European Commission
ENTSOG	the European Network of Transmission System Operators for Gas
EU	the European Union
Gas Directive	Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (OJ L 211, 14.8.2009, p. 94)
Gas Regulation	Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (OJ L 211, 14.8.2009, p. 36)
INT NC	Commission Regulation No 2015/703 establishing a Network Code on Interoperability and Data Exchange Rules (OJ L 113, 1.5.2015, p. 13)
IP	interconnection point, as defined by Article 3(10) of the CAM NC
ITC mechanism	inter-TSO compensation mechanism
LNG	liquefied natural gas
MS(s)	Member State(s)
NC	Network Code
Non-IP	non-interconnection point, point other than interconnection point
Old CAM NC	Commission Regulation No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009 of the European Parliament and of the Council (OJ L 273, 15.10.2013, p. 5)
NRA	national regulatory authority
RPM	reference price methodology
TAR NC	the Network Code on Harmonised Transmission Tariff Structures for Gas
TP	Transparency Platform of ENTSOG
Transparency Guidelines	Chapter 3 of Annex I to Regulation (EC) No 715/2009
TSO	transmission system operator
VIP	virtual interconnection point
VTP	virtual trading point

Publisher: ENTSOG AISBL
Avenue de Cortenbergh 100
1000 Brussels, Belgium

Co-Authors: Malcolm Arthur, Irina Oshchepkova, Laurent Percebois, Seán Kinsella,
Andreas Martens, ENTSOG Tariff Working Group Members

Design: DreiDreizehn GmbH, Berlin | www.313.de

ENTSOG AISBL

Avenue de Cortenbergh 100
1000 Brussels, Belgium
Tel. +32 2 894 51 00

info@entsog.eu
www.entsog.eu