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Observations d'ENGIE au projet d'arrêté (B)1718 // Volet 'Stockage'

To consult.1718

Bonjour,

Veuillez trouver en annexe les observations d'ENGIE au projet d'arrêté modifiant l'arrêté (Z)141218-CDC-1109/7 fixant la méthodologie tarifaire pour le réseau de transport d'électricité et pour les réseaux d'électricité ayant une fonction de transport.
Ces observations portent sur le volet « stockage » du document de consultation publique.
Veuillez noter que les différents documents sont également envoyés ce jour par pli recommandé à l'attention de Mr. L. Jacquet.
Annexes :

1. Note récapitalutive – commentaires ENGIE
2. Etude Deloitte – Document 1 "Benchmark report on PHS profitability drivers in Western Europe"
3. Etude Deloitte – Document 2 "Note on the realistic assessment of profitability for the Coo-Trois Ponts PHS plant"
4. Etude Deloitte – Joint Executive Summary
5. Scan lettre d'accompagnement envoyé à la CREG c/o Mr. L. Jacquet

Nous restons à votre disposition pour toute question sur ces différents documents.
Bien à vous.

Réaction d'ENGIE au document de consultation publique 1718 – Volet « Stockage »

1. Objectif

Par la présente note, ENGIE souhaite informer la CREG de ses observations quant au projet d'arrêté – soumis à consultation publique le 9 Février 2018 – modifiant l'arrêté actuel fixant la méthodologie tarifaire pour le réseau de transport d'électricité.

Les observations reprises ci-après concernent le volet « Stockage » de la consultation publique.

2. Commentaires d'ENGIE

a. Rappel du contexte légal

L'accord de gouvernement fédéral prévoit un encouragement nécessaire du stockage d'électricité.

Une définition du stockage d'électricité – ne l'apparentant plus à de la consommation et de la production d'électricité – a d'ailleurs été intégrée dans la loi relative à l'organisation du marché de l'électricité, tout comme la nécessité de prévoir des incitants :

Art. 12, par. 5: *«(…) 27° Pour les installations de stockage d'électricité raccordées au réseau de transport ou aux réseaux ayant une fonction de transport,* ***la méthodologie tarifaire contient des incitants qui encouragent le stockage d'électricité de façon non discriminatoire et proportionnelle****. Pour ce faire, un* ***régime tarifaire distinct pour le stockage d'électricité*** *peut être déterminé par la Commission.* »

b. Dans les circonstances actuelles, la continuité de l'exploitation de la centrale de Coo à sa capacité actuelle est fortement compromise

Les coûts de réseau représentent une partie considérable des coûts d'exploitation, soit plus de 50%.

La tarification des coûts d'utilisation du réseau de transport appliquée aux unités de pompage turbinage en Belgique met la centrale de pompage de Coo dans une situation financière intenable.

Dans ces circonstances, nous ne parvenons plus à justifier les investissements de maintenance nécessaires pour garder la pleine capacité de la centrale disponible.

Les unités de Coo jouent pourtant un rôle primordial dans le réseau électrique belge puisque leur puissance de plus de 1000MW disponible quotidiennement offre les avantages suivants :

1° Lissage des prix de l'électricité lors des périodes de pointe de consommation (i.e. diminution des pics de prix) ;

2° Contribution à la garantie de la sécurité d'approvisionnement et à l'équilibre du système électrique belge.

c. Missions d'étude confiées au consultant Deloitte

En tant qu'exploitant, ENGIE constate que les centrales de pompage turbinage similaires dans les pays voisins ne souffrent pas des mêmes difficultés, en témoignent les grands investissements de maintenance et d'extension de capacité qui y sont réalisés dans le cadre de la transition énergétique.

Afin d'objectiver ces observations, nous avons demandé au bureau de consultance Deloitte de reprendre l'étude réalisée en Décembre 2017 pour le compte de la CREG (portant sur la comparaison des coûts de transport supportés par le stockage en Europe), et de la compléter par deux analyses supplémentaires :

1° Analyse comparative des vecteurs de rentabilité du stockage dans plusieurs pays intégrés au marché belge[1] ;

2° Evaluation réaliste de la rentabilité de la centrale de Coo[2] ;

Nous joignons en annexe ces deux analyses menées par Deloitte – de même qu'un « executive summary » commun[3] – et considérons à ce titre qu'elles font partie intégrante de nos observations par rapport à la présente consultation.

d. Résultats des analyses de Deloitte

- Deloitte a d'abord comparé les principaux vecteurs influençant la rentabilité du grand stockage par pompage-turbinage (revenus du marché de l'électricité, coûts de réseau, revenus du marché de rémunération de capacité) dans les pays fortement couplés à la Belgique, c'est-à-dire la France, Allemagne, le Royaume-Unis, l'Autriche, le Grand-Duché de Luxembourg et les Pays-Bas.

  Il en ressort que la Belgique est largement défavorisée par rapport aux autres pays.

  Les tarifs de transport appliqués au stockage sont largement plus élevés en Belgique qu'en France, en l'Allemagne et en Autriche.

  Seul le Royaume-Uni présente des tarifs de transport supérieurs à la Belgique mais ceux-ci sont compensés par les revenus importants provenant du marché de capacité (CRM), positionnant même le Royaume-Uni en tête de profitabilité pour le pompage-turbinage.

- Ensuite, Deloitte a étudié de la manière la plus réaliste possible la profitabilité d'une centrale de stockage par pompage-turbinage de 1000 MW en Belgique.

  Cela implique notamment d'inclure la centrale de stockage dans un portefeuille d'assets de production, afin de lui permettre de participer au marché des services ancillaires.

  Cette seconde étude démontre que la marge brute maximale (définie comme étant égale à l'ensemble des revenus desquels sont déduits les coûts de transport actuels) que la centrale de stockage belge pourrait capter, est de l'ordre de 10 millions d'euros par an.

  Cela confirme qu'une centrale de stockage telle que Coo peut difficilement couvrir ses frais opérationnels (comprenant le personnel, la maintenance récurrente, les assurances et taxes,…), estimés à 10 millions d'euros par an.

  Il ne reste ainsi plus aucune marge résiduelle pour couvrir les grands investissements récurrents de maintenance, s'élevant en moyenne à 5 millions d'euros par an (exemples : rénovation de l'étanchéité du bassin supérieur n°1, rénovation du bassin inférieur, rebobinage des stators,…).

  En conséquence, une réduction substantielle des tarifs de réseau appliquée au grand stockage raccordé au réseau de transport est indispensable pour réaliser les investissements nécessaires à garantir la disponibilité des unités de la centrale de Coo.

[1] *Assessing the economic conditions of Belgian pumped-hydroelectric storage: comparative review of profitability drivers in Europe and evaluation of the current situation - Document 1: Benchmark report on PHS profitability drivers in Western Europe*, Deloitte, 23 February 2018

[2] *Assessing the economic conditions of Belgian pumped-hydroelectric storage: comparative review of profitability drivers in Europe and evaluation of the current situation - Document 2 : Note on the realistic assessment of profitability for the Coo-Trois Ponts PHS plant,* Deloitte, 23 February 2018

[3] *Assessing the economic conditions of Belgian pumped-hydroelectric storage: comparative review of profitability drivers in Europe and evaluation of the current situation - Joint executive summary*, Deloitte, 23 February 2018

L'étude démontre d'ailleurs qu'une réduction des tarifs de transport de l'ordre de 50% permettrait juste à la centrale de Coo de couvrir ses coûts opérationnels ainsi que les grands investissements de maintenance.

e. La proposition d'adaptation de la méthodologie tarifaire par la CREG ne permet pas de faire des investissements d'extension des installations

Les 3 raisons pour lesquelles la proposition est économiquement inacceptable sont les suivantes :

1. La proposition d'adaptation de la méthodologie tarifaire prévoit qu'une exemption partielle (80%) est conditionnée à des investissements d'augmentation de puissance et de capacité (plus de 7,5%), pour une durée de 5 ans à dater de la mise en service.

   - Une **augmentation de l'énergie stockée** de plus de 7,5% implique d'augmenter les volumes des bassins de Coo d'environ 600 000 m³. Cela représente un investissement estimé à 30 millions d'euros, avec une mise en service opérationnelle au plus tôt fin 2020 (long processus d'autorisation et travaux de génie civil).

   - Une **augmentation de puissance** de plus de 7,5% implique de remplacer des composants principaux (turbines, transformateurs,…) et d'adapter les autres composants sur 3 des 6 groupes turbopompes de la centrale de Coo. Cela nous obligerait à avancer de plusieurs années des grands travaux de démontage pour un montant estimé à 20 millions d'euros et de consentir en plus un investissement de 10 millions d'euros pour l'augmentation de puissance. L'ensemble des travaux sur les 3 unités ne pourraient être achevés qu'en 2023 au plus tôt.

   Etant donné que la durée d'exemption partielle des coûts de transport – dans la proposition actuelle – se limite à 5 ans, il n'est pas possible d'envisager un double investissement simultané sur une augmentation de puissance et sur une augmentation d'énergie stockée.

2. En outre, l'exemption partielle proposée n'entrant en vigueur qu'à la mise en service de l'ensemble des projets d'extension, cela signifie que les tarifs de transport actuels seraient maintenus inchangés jusqu'en 2023. Ceci est intenable pour la centrale de Coo.

3. Limiter la durée d'exemption à 5 ans crée une période d'opportunité bien trop courte pour favoriser de grands investissements (de rénovation et d'extension) qui nécessitent une visibilité sur 10 ans, comme le régime d'exemption allemand le prévoit.

3. Conclusion

ENGIE croit en l'importance du grand stockage pour accompagner au mieux la transition énergétique, en facilitant l'intégration de la production renouvelable intermittente et afin de garantir l'équilibre du système électrique et de la sécurité d'approvisionnement.

ENGIE est prêt à investir dans la centrale de Coo, que ce soit pour prolonger la durée de vie des installations existantes ou envisager des projets d'extension.

L'adaptation de la méthodologie tarifaire proposée ne crée pas les conditions permettant à ENGIE de réaliser ces investissements.

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Deloitte.

Assessing the economic conditions of Belgian pumped-hydroelectric storage: comparative review of profitability drivers in Europe and evaluation of the current situation

Document 1: Benchmark report on PHS profitability drivers in Western Europe

23 February 2018 – Final version

Strictly confidential

Prepared at the request of Electrabel

Table of contents

Executive summary

1. Despite the recognized value of energy storage for flexibility or peak shaving, its commercial development remains limited due to the persisting presence of market or regulatory barriers (technical constraints for participation to ancillary services, double counting of charges on both injection and withdrawal…) as well as limited opportunities to benefit from the spreads on energy markets. A dynamic wave of reforms is now taking place throughout Europe to tackle these issues and help place storage at the center of opportunities on the energy market along with demand response and generation. Several European countries have already adapted their regulatory framework to enable a more massive development of storage and to secure operation of current assets.

2. In Belgium, several recommendations were made as soon as 2015 by the energy regulator CREG to encourage storage development, targeting in particular the economic barriers linked with network tariffs. They were followed by an amendment of the Belgian Electricity Law[1], which exonerates storage facilities from the federal levy and also gives the CREG the possibility to create a special tariff regime for storage. In this respect, the CREG commissioned in June 2017 a study comparing the transmission network costs incurred by storage facilities in eleven European countries[2]. The study was carried out by the Economic Advisory team of Deloitte France and was the basis of the CREG's proposals for a specific tariff regime in the current public consultation on the evolution of transmission network charges[3]. In this context, Electrabel mandated the same study team to continue the work on questions regarding the competitive state of Belgian pumped hydro storage (PHS) compared to the neighboring countries. In particular, the previous work on the playing field regarding transmission related costs is to be continued and focused on a more restricted scope, both geographically and technologically.

3. This new study is structured into two steps: i) the benchmark of PHS economic conditions in Europe and ii) the realistic assessment of profitability of existing Belgian PHS. The present report covers the first step and focuses on assessing the costs and revenues that a private operator of PHS would experience in Belgium and the neighboring countries with which it is highly coupled: Austria, France, Germany, Great Britain, Luxembourg and the Netherlands. The focus on PHS is of significant importance for Electrabel, which operates the largest pumped storage facility in Belgium (Coo – Trois Pont). It is also highly relevant as PHS remains the most mature and available storage technology in Europe. The new benchmark thus looks to assess the position of Belgian PHS compared to its neighboring from the point of view of private operators and investors, which would aim to build the most competitive portfolio of assets throughout Europe. For each country, it identifies and looks to quantify the drivers which influence the profitability of PHS, in terms of costs and revenue streams. The results are used to study the correlation between Belgian PHS profitability and its national regulatory framework, and to assess the existence (or lack thereof) of a level playing field for PHS in the region.

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[1] *"13 Juillet 2017. — Loi modifiant la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité en vue d'améliorer la flexibilité de la demande et le stockage d'électricité"*. See the document available here: http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&table_name=loi&cn=2017071306

[2] "Comparison of Belgian transmission network costs incurred by an idealized storage facility with those in other European countries", available as appendix of consultation 1718 (see next footnote).

[3] Consultation 1718 on the « Projet d'arrêté modifiant l'arrêté (Z)141218-CDC- 1109/7 fixant la méthodologie tarifaire pour le réseau de transport d'électricité et pour les réseaux d'électricité ayant une fonction de transport », launched on 9 February 2018.
The regulator proposes 1) a full exoneration from the network costs to new storage plants during 10 years; and 2) a 80%-exoneration for existing storage plants during five years provided that they undertake improvement works to increase their installed capacity and the size of their reservoir by 7.5%.

Methodology

4. Profitability drivers of PHS storage are assessed for six European countries: Austria, Belgium, France, Germany, Great Britain and the Netherlands. Luxembourg, while in the scope of the benchmark, is not studied individually because the Luxembourgian PHS plant (Vianden) is connected to the German network of Amprion. Besides, the analysis of drivers for the Netherlands is limited to a qualitative analysis and a comparison of transmission costs and taxes with the other countries: as the Dutch potential for PHS is null, its inclusion in the main comparison of preferences from an investor point of view does not make sense.

5. The profitability drivers in each country were analyzed both qualitatively and quantitatively. With regard to revenue streams, the benchmark includes (i) revenues from the arbitrage on the day-ahead energy market (DA or day-ahead hereafter), (ii) revenues from the provision of ancillary services and (iii) revenues from capacity remuneration mechanisms. With regard to incurred costs, it includes (iv) transmission related costs such as tariffs or system management costs and (v) taxes and surcharges that the plant has to pay as a consumer or a producer of electricity. All other costs (personnel, maintenance, etc.) are considered equivalent. Therefore, they should not distort the profitability balance between countries and are not included in the benchmark.

6. The quantitative benchmark is based on simulations of a modeled PHS plant for the year 2017, with varying assumptions regarding its regulatory and fiscal framework as well as the characteristics of the different revenue streams (prices, volumes, conditions for participation…). The main set of simulations models the behavior of PHS plants when they are able to participate to energy markets and on CRMs only. The methodological choice to focus on these two revenue streams and to keep ancillary services for the sensitivity analysis stems from the modeling constraints, which prevents from modeling the behavior on ancillary services with the same level of precision and comparability[4] than on the day-ahead and on CRMs. Beside the exclusion of ancillary services, several simplified assumptions have to be taken to ensure a level comparison between countries and to cope with the lack of essential data which would have enabled a modeling as realistic as possible. Hence, effects such as imperfect foresight of prices, market resilience or the possibility of paradoxically rejected offers are not taken into account, and the results are therefore optimistic, constituting an upper boundary of the profitability outlook. It is nevertheless expected that these assumptions affect all compared plants with a similar order of magnitude, thus not distorting the validity of results. To summarize, the main simulations' outputs yield a reasonable picture of the comparable levels of profitability between countries, when the modeled plants do not participate to ancillary services. They should be used to compare the relative levels of profitability between countries, but they do not enable to estimate the actual profitability that an actual plant might display (this is the objective of the study's second step).

7. The other sets of simulations enable to test additional impacts, assumptions and sensitivity analyses: (i) the impact of an eventual tariff exemption for Belgian PHS, (ii) the impact of each national regulatory and fiscal regime if it was applied to a plant playing on the Belgian markets, (iii) the impact of the idealistic theoretical participation to ancillary services, and (iv) the year of analysis on the energy market.

8. The simulations do not directly compare profits, instead focusing on the 'idealized' gross margins[5] before operational and maintenance costs. One assumes identical modeled plants which operate

[4] In particular, lack of data and the need to realize a fair comparison of all countries required to assume hydraulic bypass, which increases significantly the possibility and profitability outlook from participating to some reserve products.
[5] Gross margin before operational and management costs is calculated as the difference between all studied costs and revenue categories. It is idealized because it is the optimized margin that the PHS plant could get in the ideal setting of the modeling. The actual gross margin should in theory be lower than in the simulations, where it is assumed that the PHS plant has perfect foresight and is completely omniscient to the future volumes and prices on the markets, and that resilience effects are not considered.

in each national setting in terms of tariffs, taxes, prices and volumes. Each plant is given the possibility to participate to energy markets and CRMs (and ancillary services, when considered), and then adjusts its decisions and arbitrages between the available revenue options to maximize its annual profit, following an economically rational strategy.

Main results

9. The results highlight the variety of PHS profitability drivers and their impact in the studied countries.

   a. Regarding transmission related costs, there is a large diversity of transmission tariffs, charges and obligations costs that the PHS plant has to pay. In some countries those costs are fixed or proportional to the installed capacity; they can also be indexed on the maximal injection or withdrawal power, which is *generally* the same. They are particularly significant in Belgium and in Great Britain. In all countries, variable charges are also applied on the total injections (e.g., injection-based tariffs or charges in Austria, Belgium, Great Britain) or withdrawals (Austria, Germany, France and Great Britain with BSUoS). Germany and Austria both present specific regulatory regimes for PHS but it translates differently: German PHS is supposed in the modeling to be eligible for a total 10-year exemption of network tariffs[6], while the specific tariffs in Austria are still significant and are completed by other charges related to network management.

   b. Regarding taxes and surcharges, all countries but Great Britain apply some to energy storage. In all countries those charges are particularly related to public service obligations for the power system and renewable subsidies. It is important to mention that fiscal frameworks are often unclear as to the nature of PHS as either an energy consumer or a producer. For example, the British framework does not explicitly state that transmission-connected PHS is considered as a producer, while in practice it seems to be the case, thus allowing a complete exemption of taxes and surcharges for the plant. In all other countries, PHS is generally considered as a consumer but exemption regimes are in place for some taxes in Belgium, Germany and Austria.

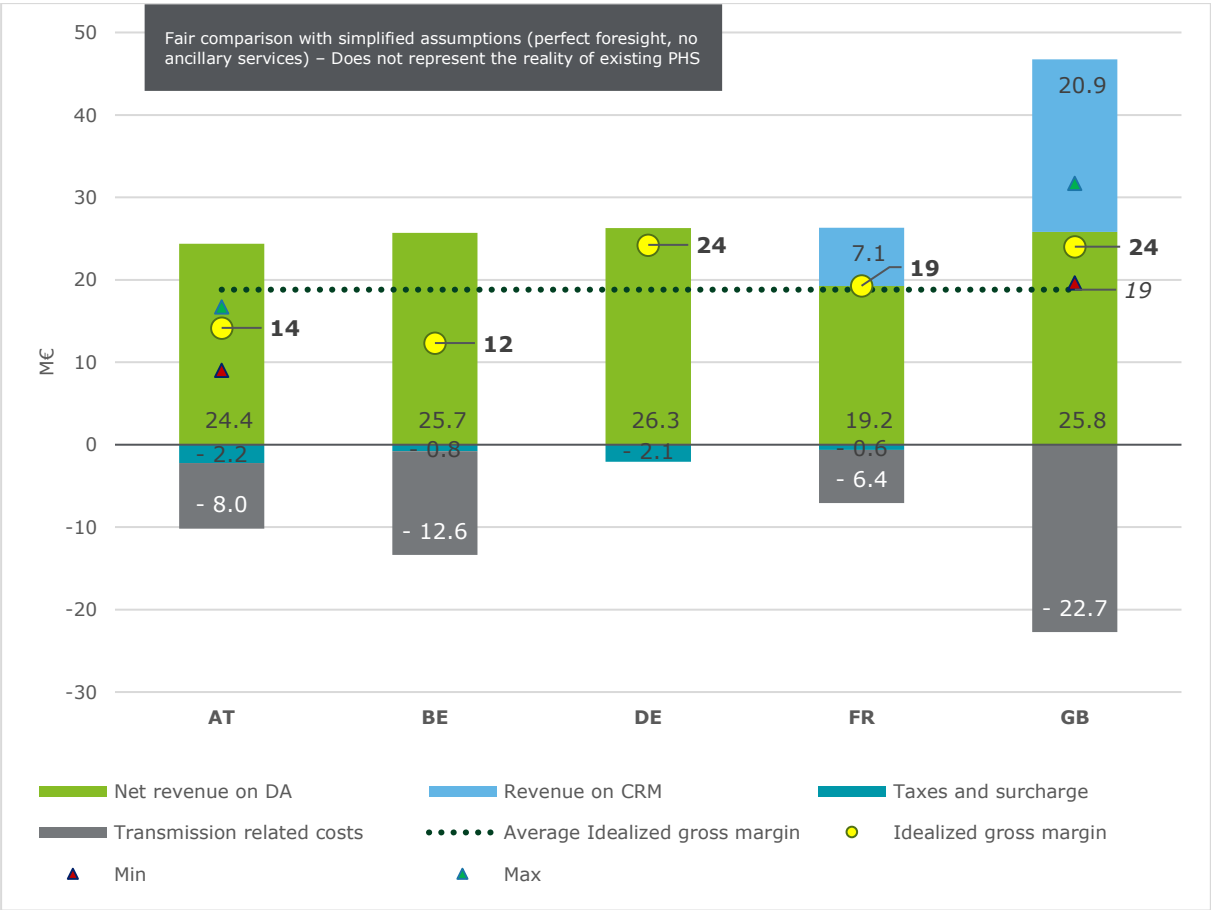
   c. Finally, the remuneration conditions of PHS are contrasted from one country to another. Firstly, all PHS plants can of course realize arbitrages on the energy markets to benefit from the spread between high and low prices, but this can amount to different outcomes depending on the national spread[7] and on the distortive effect of energy-based costs and tariffs, which affect the economic decisions of the operator. Secondly, only France and Great Britain have capacity remuneration mechanisms (capacity markets) which are suitable for PHS, as strategic reserves in Germany and Belgium would not be interesting for storage plants in operation. The gain in profitability thanks to these markets is very high, even if their existence may theoretically be accompanied by a decrease of available spreads on the energy markets (producers do not have to bid at the highest prices anymore because they cover their fixed costs through capacity market revenue). Finally, the conditions of participation, the volumes at stake and the prices are very divergent for ancillary services.

[6] All storage built in Germany after 4 August 2011 benefits from a 20-year exemption. However, for the study's purpose one assumes for Germany a PHS plant built before 4 August 2011. Such a plant can also benefit from a 10-year exemption of network tariffs if its technical characteristics have been improved: size of reservoir should be increased by at least 5% <u>or</u> their turbine output should be increased by at least 7.5%. The exemption begins at the date of the expansion's commissioning. It is generally known that a large majority of old PHS in Germany have made these improvements to benefit from the exemption. Therefore, this is what one also assumes for the PHS German plant in the study.
[7] The spreads are national when congestions appear on interconnections. Meanwhile, DA prices in Germany and Austria are always identical.

The revenue that PHS can earn on these services is closely linked to the technical constraints but also to the pool of revenue available, which induces major differences in profitability.

10. Quantitatively, the results translate into differences in energy volumes, earned revenues, incurred costs and therefore gross margin levels from one country to another. The following figures present the main outcomes of the simulations, assuming that PHS can participate to day-ahead markets and capacity remuneration mechanisms. Figure 1 shows the level and the breakdown of theoretical gross margins that can be earned by the PHS modeled plants if they operate in each country, where they face the corresponding regulatory and fiscal framework as well as revenue conditions. Figure 2 provides a closer look at the corresponding costs related to transmission networks.

Figure 1. **Comparison of idealized gross margins earned by the modeled PHS plant – Simulations for year 2017 with participation to DA markets and CRMs**



Source : Deloitte – Economic Advisory

11. The quantitative results for participation to DA and CRM confirm that France, Germany and Great Britain are the most favorable countries for PHS with a gross margin around or higher than € 20 million. They place Belgium at the bottom of the profitability ladder.

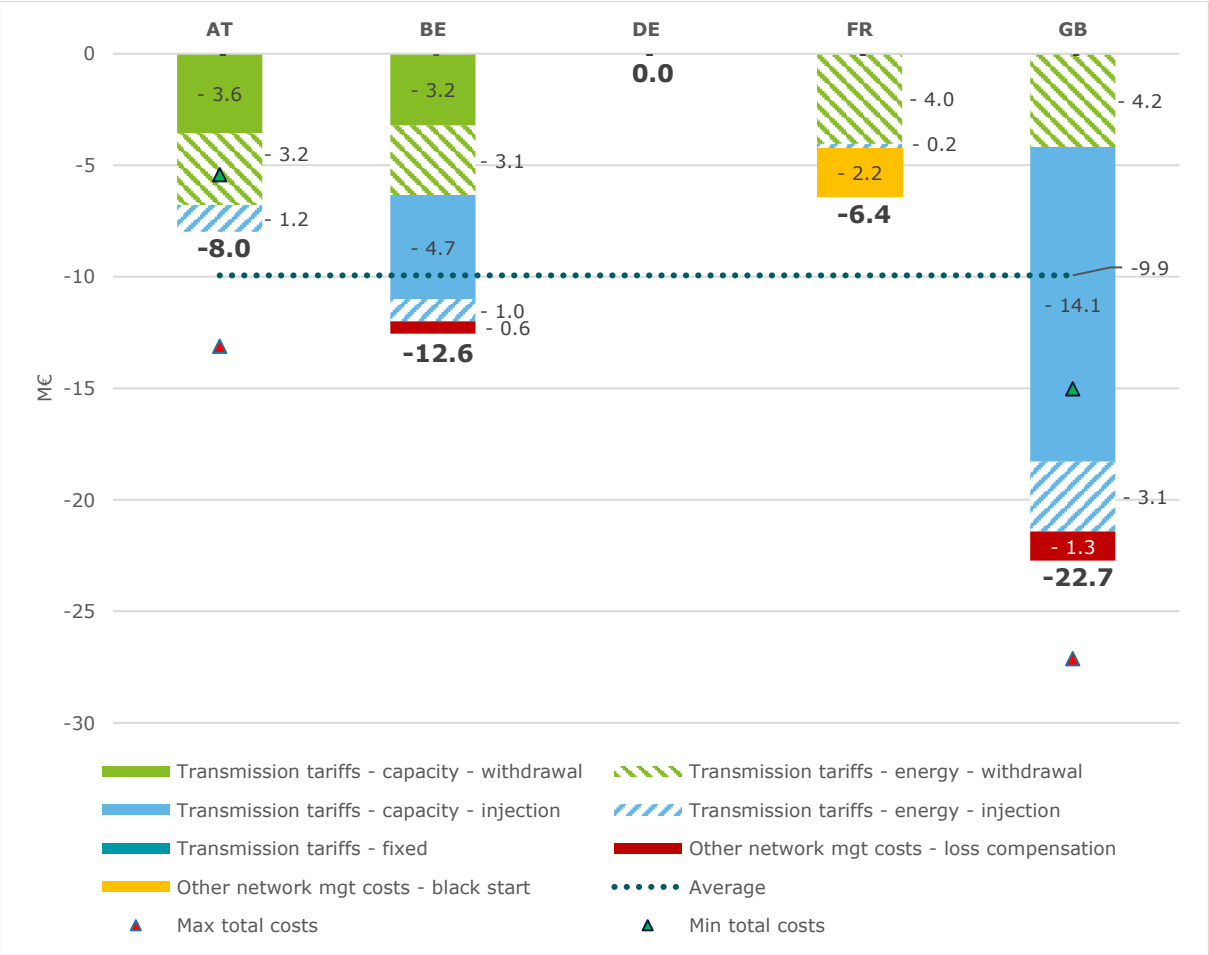
    a. France, Germany and Great Britain benefit from specific advantages which enable them to retain the quasi entirety of their net revenue on the day-ahead. In France and Great Britain, revenue from capacity markets (respectively € 7 and 21 million) almost compensate the incurred costs and taxes, which is particularly important in the British case, where the capacity-based tariffs are very unfavorable to storage plants (which present a lower load

factor than other producers). German PHS is meanwhile assumed to fulfill the conditions for tariff exemption[8], which helps it realize the best idealized gross margin in this simulation.

b. Austria is in an intermediary position on average, but a closer look shows that the tariffs in regions where PHS is actually located (Vorarlberg and Tyrol) are 6 €/MWh (withdrawn) lower than in the rest of Austria. In these regions, the total cost related to transmission tariffs is € 5 million and the idealized gross margin reaches € 17 million, which isolates even more Belgian PHS as the lowest idealized gross margin earner.

c. Belgium does not benefit from a level playing field with the other countries. Without ancillary services, PHS idealized gross margin is only € 12 million, twice as low as in GB and Germany, and 30% lower than the average for the five countries. This comes despite a net margin on the day-ahead (€ 26 million) close to the average of analyzed countries. The profitability of Belgian PHS is instead impacted by very high transmission tariffs (€ 12 million), second only to Great Britain.

Figure 2. **Comparison of simulated transmission related costs paid by the modeled PHS plant – Simulations for year 2017**



Source : Deloitte – Economic Advisory

12. The closer look at transmission related costs highlights the strong divergences of regulatory frameworks from one country to another. They confirm the qualitative analysis of those frameworks. The tariff designs are especially critical for Belgian and British PHS, which incur

[8] Conditions for PHS build before 4 August 2011 (see footnote 6)

transmission tariffs higher than € 10 million. In both countries, the share of capacity-based tariffs in total incurred costs is significant. It is largely expected because capacity tariffs tend to penalize (consumption or generation) facilities with a low load factor, like PHS. Note that energy-based tariffs (and other costs) also have an indirect significant impact on profitability because they distort the price signals on the energy markets (higher buying or selling prices on the energy market), reducing the number of spreads that the storage plant can monetize.

13. The previously described outputs concern the case where PHS can only participate to the day-ahead energy market and CRMs. As explained in the methodology, they give an optimistic[9] yet reasonable[10] insight on the behaviors and profitability of PHS when plants cannot participate to ancillary services. In the sensitivity analysis, it was however possible to realize a preliminary theoretical assessment of PHS' participation to frequency reserves. This analysis was based on the most extreme assumptions which would maximize the provision and the monetization of frequency services, such as full technical possibility to do hydraulic bypass or the assumption that the plant can earn 100% of the market without influencing its price (price-taker with no resilience). The extreme nature of these assumptions makes them unrealistic and represent the (unreachable) upper boundary when all realistic constraints are relaxed. They should not be regarded with the same level of certainty and realism than the benchmark's main set of results, but they provide some very striking findings for each country. In particular, they show that even extremely optimistic assumptions as to the participation to frequency services do not enable Belgian PHS to compensate for its lag in profitability, especially with regard to France, Germany and Great Britain.

14. It should be noted that in reality profitability is more relevant to the investor than gross margins, both for comparison with other countries as well as for decisions regarding new investments or closure. Profitability is extracted from gross margins by subtracting all other costs such as remaining operational cost (personnel, market dispatch, insurances…) or costs related to lifetime extension works, which can amount to respectively € 10 and 5 million for a PHS plant similar to the one that is modeled in the study[11]. This does not change the benchmark's main conclusions as to the place of Belgian PHS compared to Austria, France, Germany and Great Britain because these additional costs are assumed to be equal in each country for the modeled plants. Furthermore, the simulations in the study take place in an idealized setting where the plant is omniscient to all future prices and volumes, is independent from any portfolio, is economically rational and is not exposed to a risk of resilience on the markets (assumption of price-taker). These simplifying assumptions were vital in order to realize a level modeling of PHS in all countries and to compare them, but they prevent from looking at the actual operating and economic conditions of PHS. It is expected that any sophistication would however lead to the same conclusions: indeed, the relaxing of major hypotheses such as perfect foresight should affect all compared plants with a similar order of magnitude.

15. In conclusion, the benchmark's results confirm that there is no level playing field between the studied countries. In particular, Belgian PHS appears to lag millions behind France, Germany and Great Britain, pulled down by relatively high transmission tariffs and not compensated by any revenue from capacity mechanisms. The results raise a second question regarding the financial viability of Belgian PHS: scientific intuition suggests that a more realistic simulation would have resulted in operating losses. This question is the subject of the second step of the study[12], which

[9] Some assumptions had to be taken to tackle modeling limitations, leading to overestimation of profitability.
[10] The orders of magnitude of profitability gaps between countries should reflect reality. As already explained, it should be reminded that those results only illustrate the relative levels of profitability from one country to another for a theoretical plant; absolute estimations of actual PHS profitability in a given country, for a given plant, should not be extracted from these values.
[11] Source: Electrabel internal analysis. The data was not crosschecked by Deloitte. Deloitte cannot be held accountable of any use of these costs and of the resulting estimations.
[12] The second step of the study is described in a second document: *Additional note on the realistic assessment of profitability for the Coo-Trois Ponts PHS plant*, 2018, Deloitte

looks at the actual economic conditions of the Coo-Trois Ponts PHS plant, and which confirms that the operating results of the plant are already durably negative, once all revenues and costs are taken into account. All of this does not bode well for the capacity of Belgian PHS to attract new investments, and can even be cause for concern regarding the sustainability of PHS in the future. With regard to the current consultation on the tariff methodology, the simulation of a tariff exemption in Belgium confirms the intuition that it should tackle the concerns on PHS profitability and help reach a level playing field with France, Germany and Great Britain.

1 Introduction and methodology

1.1 Context and objectives

16. It is now widely accepted that large-scale electricity storage and especially pumped-hydro storage (PHS) provides several types of benefits to the electricity market in the context of the energy transition. Indeed, pumped-hydro storage can benefit the entire energy market by :

    a. Enabling the storage of the overflow of electricity (for example, produced by intermittent generations) and thus enabling arbitrages (between peak and off-peak periods, between high and low prices periods),

    b. Reducing the need of additional peak capacity by adding more capacity available,

    c. Bringing more flexibility to the system (for example, by providing frequency reserves).

17. However, the monetization of the benefits brought by electricity pumped-hydro storage is not obvious at first glance and remains limited. Indeed, the spread between peak and off-peak periods does not enable a sufficient remuneration to PHS. In addition, electricity storage also has to cope with technical constraints, such as the participation to reserve and ancillary services.

18. In addition, pumped storage facilities face significant costs, in particular related to the use of the transmission network, both as a consumer and as a producer. These facilities also have to pay significant taxes and legal surcharges. These costs can distort investment and operation signals to storage operators. They do not enable the economically optimal development of storage as well as the sustainable operation of existing facilities. Therefore, the profitability of a pumped-storage facility is not ensured while it is essential for the success of the energy transition. It may not reflect the benefits that storage can have for the functioning of the electricity market. In addition, in a competitive and interconnected European electricity market, the comparison of the profitability must be made between interconnected market places. Indeed, the more the interconnection is developed, the more competition between generation and demand side resources crosses borders.

19. In this context, the European Commission, through its Clean Energy for All Europeans package in 2016, highlighted the need for a level playing field, in term of competition, between storage, generation and demand-side resources. As a result, several European countries (e.g. Italy, Spain, Portugal, Germany, Austria) have already adapted their regulatory framework in order to enable the massive development of large-scale (pumped) storage facilities.

20. In Belgium, several recommendations were made as soon as 2015 by the energy regulator CREG to encourage storage development, targeting in particular the economic barriers linked to network tariffs. They were followed by an amendment of the Belgian Electricity Law[13], which exonerates storage facilities from the federal levy and also gives the CREG the possibility to create a special tariff regime for storage.

21. In this fast moving context, the CREG asked the Economic Advisory team of Deloitte France to perform a comparative study of network charges incurred by national Transmission System

[13] "*13 Juillet 2017. — Loi modifiant la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité en vue d'améliorer la flexibilité de la demande et le stockage d'électricité*". See the document available here: http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&table_name=loi&cn=2017071306

Operators (TSO) to an idealized storage facility between Belgium and eleven European countries[14]. The study was the basis of the CREG's proposals for a specific tariff regime in the current public consultation on the evolution of transmission network charges[15].

22. As requested by the CREG, the first study focused on electricity storage in general and not on a specific technology. Besides, it concerned transmission costs incurred by storage facilities and did not encompass all the other drivers of storage profitability. In this context and in agreement with the CREG, Electrabel, which is one of the largest players in the Belgian electricity market and which operates the largest pumped storage facility in Belgium (Coo – Trois Ponts), asked the same team of Deloitte Economic Advisory to focus the study on pumped-storage only and to extend the work to profitability on the whole (while still studying the impact of each country's transmission related costs on profitability). Profitability encompasses all costs and revenues associated with PHS operation.

23. The new study is structured into two steps: i) the benchmark of PHS economic conditions in Europe and ii) the realistic assessment of profitability of existing Belgian PHS. The present report covers the first step. Its purpose is to identify and assess the profitability drivers of hydro-pumped storage in Belgium compared to the European countries that are highly coupled with the Belgian market (i.e. France, Germany, Austria, the Netherlands, Luxembourg and Great Britain). The analysis is done from the point of view of a rational investor who aims to build the most competitive portfolio of assets throughout Europe. The study compares qualitatively and quantitatively the costs that the plant has to incur and the different revenue streams it can earn in the different studied countries. It must be noted that the reasoning does not seek to identify the country or the area where storage would be most beneficial to the electricity market from a global economic point of view[16], but from a private point view, i.e. to see where investors would go (where there profit are maximized). Furthermore, the fair comparison of profitability drivers between countries requires making simplified assumptions that place the results in a theoretical framework. The realistic assessment of profitability for actual PHS cannot be drawn from this report and would require more accurate and complex calculations. This is the objective of the study's second step, focusing on the Belgian Coo-Trois Ponts PHS plant, and which is presented in a second note complementary to this report.

24. The present benchmark report answers two main questions that lead the reasoning and the interpretation of the results:

    a. Does the Belgian regulatory framework (especially in terms of transmission network charges, taxes & surcharges on electricity) ensure a level playing field between Belgian and neighboring PHS?

    b. What would be the impact of an exemption from transmission network charges in terms of profitability for a pumped-storage facility in Belgium?

25. The remaining of this report is structured as follows: in the next section, the general methodology of this study is described. This methodology is based on a qualitative and a quantitative

[14] "Comparison of Belgian transmission network costs incurred by an idealized storage facility with those in other European countries", available as appendix of consultation 1718 (see next footnote).
[15] Consultation 1718 on the « Projet d'arrêté modifiant l'arrêté (Z)141218-CDC- 1109/7 fixant la méthodologie tarifaire pour le réseau de transport d'électricité et pour les réseaux d'électricité ayant une fonction de transport », launched on 9 February 2018.
The regulator proposes 1) a full exoneration from the network costs to new storage plants during 10 years; and 2) a 80%-exoneration for existing storage plants during five years provided that they undertake improvement works to increase their installed capacity and the size of their reservoir by 7.5%.
[16] I.e. where the storage plant will reduce system costs and will guarantee the success of the energy transition at least costs.

benchmark. Then, the findings from the qualitative benchmark are described. Finally, results from the quantitative study are compared for the considered countries.

1.2 Methodology

26. The main goal of the present report is to estimate and to compare the profitability drivers of a pumped-hydro storage facility between Belgium and six countries (Austria, France, Germany, Great Britain, Luxembourg, and the Netherlands). Luxembourg is however excluded from the benchmark because the only PHS operated on the Luxembourgian territory is directly connected to Amprion network and thus presents the same characteristics than German PHS's (in term of costs and revenues).

27. To perform the study, the functioning and commercial decisions of a pumped-hydro storage facility are modeled, taking into account the different revenue streams in each country as well as the costs that would be incurred to the pumped-hydro storage facility.

28. The study is based on three main categories of revenues :

    a. Revenues from the arbitrage on the day-ahead market. It consists of a financial arbitrage between periods of high prices (when the facility injects electricity and thus sells electricity) and low prices (when the facility withdraws electricity from the grid, to store and re-inject later)

    b. Revenues from the provision of ancillary services

    c. Revenues from Capacity Remuneration Mechanisms (CRM), in countries where they are implemented

29. Two main cost categories are considered in the study (as of 1st January 2018) :

    a. The transmission network charges and other costs related to the use of the electricity transmission network (loss compensation, other obligations…)

    b. The taxes and surcharges on electricity

30. The study considers that all others costs are equivalent in each country. Therefore, they are not implemented in the model (but they are still being taken into account in the interpretation of results). In other words, it is assumed that the capital expenditures and operation & maintenance expenditures are equivalent in all countries.

31. With regard to the revenue opportunities, the modeled pumped-hydro storage facilities are assumed not to be part of asset portfolios (which is very important, for example, for reserve provision). This reduces their ability to provide ancillary services but it allows for the comparison of equivalent standalone PHS plants, which only differ by their national regulatory setting. The plant is supposed to have 100% perfect foresight and omniscience with regard to its operation on energy markets and ancillary services.

Benchmarks and simulations

32. The benchmark is performed both qualitatively (in section 2) and quantitatively (in section 3).

33. The qualitative benchmark describes the complete overview of revenue streams and cost drivers for PHS in the studied countries. The main differences between national contexts and regulatory frameworks are highlighted, and the most important drivers of PHS profitability are detailed.

34. For the purpose of quantification, a PHS plant is modeled with the same technical characteristics and economic behavior in all countries. Several sets of simulations are then performed, enabling to measure the impact that each country's characteristics can have on PHS profitability. The main year of analysis is 2017. Each set of (national) simulations enables different quantitative benchmarks.

    a. The main set of simulations modeled the behavior of PHS plants when they are able to participate to energy markets and on CRMs only. The methodological choice to focus on these two revenue streams and to keep ancillary services for the sensitivity analysis stems from the modeling constraints, which prevents from modeling the behavior on ancillary services with the same level of precision and comparability[17] than on the day-ahead and on CRMs. Beside the exclusion of ancillary services, several simplified assumptions also had to be taken to ensure a fair comparison between countries and to cope with the lack of essential data which would have enabled a modeling as realistic as possible. Hence, effects such as imperfect foresight of prices, market resilience or the possibility of paradoxically rejected offers are not taken into account, and the results are therefore optimistic, constituting an upper boundary of the profitability outlook. It is nevertheless expected that these assumptions affect all compared plants with a similar order of magnitude, thus not distorting the validity of results. To summarize, the main simulations' outputs yield a reasonable picture of the comparable levels of profitability between countries, when the modeled plants do not participate to ancillary services. They should be used to compare the relative levels of profitability between countries, but they do not enable to estimate the actual profitability that an actual plant might display (this is the objective of the study's second step, with a focus on Belgian PHS).

    b. The other sets of simulations enable to test additional impacts, assumptions and sensitivity analyses: (i) the impact of an eventual 100% tariff exemption for Belgian PHS, (ii) the impact of each national regulatory and fiscal regime if it was applied to a plant playing on the Belgian markets, (iii) the impact of the idealistic theoretical participation to ancillary services, and (iv) the year of analysis on the energy market.

    c. It must be noted that the quantitative benchmarks' outputs do not directly present the profitability in each country, but rather the gross margin before operational (personnel, small maintenance, …) and major maintenance costs (see section 3.2.1). As already explained, the other costs are assumed equivalent between countries. This gross margin is defined as 'idealized', because the modeled plant is supposed to be omniscient and rational (see section 3.1).

    d. The table on the next page describes all the sets of simulations (benchmarks) which were performed. More explanation is available in section 3 when the results are commented.

[17] In particular, lack of data and the need to realize a fair comparison of all countries required to assume hydraulic bypass, which increases significantly the possibility and profitability outlook from participating to some reserve products.

Table 1. Summary of quantitative benchmark simulations

	Quantitative benchmark Simulation 1					**Quantitative benchmark Simulation 2**					**Quantitative benchmark Simulation 3**					**Quantitative benchmark Simulation 4**				
What for?	Compare the impacts of the national regulatory framework and market characteristics on DA and CRM					Compare the impacts of the national regulatory framework and market characteristics on DA, CRM and optimistic theoretical provision of frequency reserves					Compare the impacts of the national regulatory framework only					Investigate the effect of a hypothetical transmission tariffs exemption in Belgium				
	DA	CRM	Frequency reserves	Market characteristics[18]	Regulatory framework[19]	DA	CRM	Frequency reserves (sensitivity analysis)	Market characteristics	Regulatory framework	DA	CRM	Frequency reserves	Market characteristics	Regulatory framework	DA	CRM	Frequency reserves	Market characteristics	Regulatory framework
AT	✓	✓	×			✓	✓	✓			✓	✓	×			Same as Simulation 1				
BE	✓	✓	×			✓	✓	✓			✓	✓	×			Same as Simulation 1 but with a transmission tariffs exemption in Belgium				
FR	✓	✓	×			✓	✓	✓			✓	✓	×			Same as Simulation 1				
DE	✓	✓	×			✓	✓	✓			✓	✓	×			Same as Simulation 1				
GB	✓	✓	×			Non studied					✓	✓	×			Same as Simulation 1				
NL	Non studied					Non studied					✓	✓	×			Same as Simulation 1				

[18] Prices on day-ahead market, products' design, volume and prices of ancillary services, remuneration on CRM…
[19] Network tariffs, taxes, surcharges

2 Findings from the qualitative benchmark

35. The term qualitative benchmark means in this section the description of the costs and revenue streams component by component, without entering into the detail of the calculations, which will be made in the quantitative benchmark (section 3)

36. The first two subsections focus on the charges that are applied to pumped storage facilities in the countries studied in the benchmark. They can be divided into transmission network charges (section 2.1) and charges relative to taxes and surcharges (section 2.2). Sections 2.3, 2.4, 2.5 describe the different revenue conditions with regard to day-ahead energy markets, capacity remuneration mechanisms and ancillary services.

2.1 Description and comparison of transmission network charges applied to pumped storage facilities

2.1.1 Transmission network charges – description of specific regulations

37. Two countries in the perimeter of the study apply specific transmission network charges for storage, and most particularly for pumped-hydro storage: Austria and Germany.

38. First, in 2011, the German regulation, through the Energy Economy Act[20], established a specific rule for storage facilities directly connected to the transmission network. A tariff exemption applies to facilities built after 4 August 2011 and expires 20 years after their initial start-up. Pumped-storage hydropower plants built before 4 August 2011 can only be exempted for 10 years provided that their technical characteristics have been improved after the before-mentioned date (the size of their reservoir should be increased by at least 5% <u>or</u> their turbine output should be increased by at least 7.5%). The exemption then begins at the commissioning of the expansion. This latter case is the assumption retained for the benchmark and the simulations[21].

39. Second, in Austria, the regulator, through the Electricity System Charges Ordinance applies specific "system network charges" for pumped-storage facilities. Pumped-storage facilities pay reduced charges for the energy withdrawn from the grid and a specific capacity charges. However, they also have to pay the other network charges components (see appendix 5.1.1 for more details), which increases their network bill.

2.1.2 Transmission network charges – capacity component

40. It is interesting to highlight that each country[22] of the study applies capacity charges, except France. However, the structure of these capacity charges vary significantly between countries.

41. The only countries that apply capacity charges to both generation and consumption are Great Britain and Belgium[23]. However, for these two countries, the computation of the capacity charges for consumers is based on consumption during peak hours (see appendix for more details on

[20] § 118 of the Energy Economy Act : http://www.gesetze-im-internet.de/enwg_2005/BJNR197010005.html#BJNR197010005BJNG002300000
[21] It is generally assumed that a large majority of old PHS in Germany have made these improvements to benefit from the exemption. Therefore, this is what one also assumes for the PHS German plant in the benchmark.
[22] Others than Austria and Germany for which the specific tariffs are considered.
[23] Annual peak demand capacity in Belgium.

Belgian & British network charges) and thus assumed equal to zero[24]. Indeed, as the PHS earn revenues from the arbitrage on the DA prices, it would not be economically rational for the facility to withdraw electricity during these periods. It must be noted that Belgium also applies monthly peak demand capacity charges. These charges are taken into account in the quantitative benchmark.

42. Capacity charges for generation in the UK are zonally fixed, with 27 areas spread across three TSOs (see appendix 5.5.1). In the results, an average for Great Britain is presented in terms of capacity charges for generators. Capacity charges for generation in Belgium are calculated on the yearly maximum production and are thus modeled in the simulations.

43. The Netherlands apply capacity charges for the use of transmission network. These charges are based on the annual and monthly highest consumptions of the storage plant connected to the transmission network.

44. In Austria, it must be noted that a capacity component for consumption is applied through the specific tariffs for pumped-hydro storage facilities. In addition to this specific capacity charge, a capacity charge has to be paid in the Austrian area (the "Provision charges").

2.1.3 Transmission network charges – energy component

45. Among all benchmarked countries, France, Austria and Belgium are the only countries to apply an energy component (in euro per MWh) in their transmission network charges. It is interesting to note that in these countries, the energy component is applied to both the electricity consumed from and the electricity injected into the grid. It is called the "double grid charges". They will decrease the profitability of PHS plants compared to other generation technologies.

2.1.4 Transmission network charges – fixed component

46. A fixed component (in euros per year) is applied in France, Belgium and the Netherlands. This fixed component is applied to the costs relative to metering in Belgium and France. In addition, a management fixed tariffs (for example, for billing services) is paid by the modeled facility in France and the Netherlands.

2.1.5 Transmission network charges – other management costs

47. "Other costs related to the transmission network's management" refer to the costs related to the provision and activation of system services as well as the costs associated with electricity losses which would not be already covered by the TSOs (and subsequently charged as part of the tariffs). They are instead borne directly by the market players (balancing parties, consumers, producers, etc.) and constitute additional costs. The costs related to the settlement of their own imbalances are disregarded in this study (it is assumed that the storage facility is perfectly balanced).

48. First, regulations within European countries do not impose the same obligations to network users in terms of provision of system services. In most countries, these obligations are remunerated but there are exceptions: in this latter case, the obligation implies a cost for the plant. This is particularly the case for black start in France, which is a mandatory service for the modeled pumped-hydro storage facility and is not remunerated by the TSO. In order to value the costs incurred by the black-start to the PHS, confidential data provided by Electrabel is used. Therefore,

[24] In Great Britain, the charge is calculated on the three peak half hours between November and March. Therefore, it is considered in the study that the modeled pumped-hydro storage facility is never consuming during these three half hours, and thus does not pay these consumption charges. In Belgium, following the same reasoning as in Great Britain, it is assumed that the pumped storage facility does not pay these charges.

black start appears to be a cost for the facility in France. In the other countries of the benchmark, system services are paid to the facility by the TSO and can compensate for the cost to deliver the service (see section 2.5).

49. Second, most of European countries (including those in the benchmark) directly cover loss costs through their tariffs: generally, the TSO buys itself electricity to cover network losses and then pass these costs on networks users through network tariffs. On the contrary, it is not the case in Belgium and in Great Britain. In both countries, a relatively similar methodology is applied. It provides that the balancing responsible parties (BRP) cover directly the losses in kind:

    a. In Belgium, the BRPs (or ARPs) must contribute in kind for each MWh withdrawn from the grid within their perimeter. In a simplified way, this means that each consumer willing to consume 1 MWh must buy for a little more, thus covering the anticipated losses. The regulator determines the loss multiplier used to define how much extra electricity they have to buy. This multiplier[25] is differentiated between peak hours and long-off peak hours.

    b. In Great Britain, a similar methodology is applied but it concerns both withdrawal and injection (each producer must inject more into the system that what it actually sells). The loss multipliers are not differentiated by tariff period but there are two distinct multipliers for injection and withdrawal.

50. Third, pumped-storage facilities in Great Britain have to pay the Balancing Services Use of System Charges. This cost in the report is calculated though the average of BSUoS prices published by National Grid in 2016 (prices for 2017 are not available as of today)[26]. As BSUoS are paid by both producer and consumer on the energy injected and withdrawn, they are classified as an energy component of the transmission network charges.

51. Table 2 summarizes the network charges that are considered in the simulations.

Table 2. Summary of network charges paid by the modeled facility[27]

	Specific tariff	Capacity charges injection	Capacity charges withdrawal	Energy charges injection	Energy charges withdrawal	Fixed tariffs	Other management costs (incl. losses & BS)
Austria	YES	NO	YES	YES	YES	NO	YES
Belgium		YES	0 in the model for annual peak – YES for monthly peak	YES	YES	YES	YES - losses
France		NO	NO	YES	YES	YES	YES – Black start
Germany	YES – Total exemption	NO	NO	NO	NO	NO	NO
Great Britain		YES	0 in the model	YES (BSUoS)	YES (BSUoS)	NO	YES – losses
Netherlands		NO	YES	NO	NO	YES	NO

[25] For instance, if the loss multiplier is equal to 1.05, this means that the consumer must pay for 0.05 MWh more each time it consumes 1 MWh%.
[26] https://www.nationalgrid.com/uk/electricity/charging-and-methodology/balancing-services-use-system-bsuos-charges
[27] This table summarizes charges paid by the modeled pumped storage facility relative to the transmission network charges only. Charges relative to taxes and surcharges are described in section 2.2.

2.2 Description and comparison of taxes and surcharges applied to pumped storage facilities

52. In addition to network charges described in the previous section, several taxes and surcharges are applied to pumped-storage facilities in the countries of the benchmark.

53. In the study, these taxes and surcharges will be presented within the following categories:

    a. Public services obligation (PSO) for Renewable Energy Subsidies (RES)

    b. Green Certificates

    c. Other Public Service Obligation (PSO)

    d. Electricity tax/levy

54. Regulations about these taxes and surcharges are very specific from a country to another. While some countries apply a specific exemption regime in term of taxes and surcharges for pumped-hydro storage (i.e. Belgium, Great Britain, Germany, Austria), others do not clearly define storage (as a consumer, a producer or both). Therefore, for these countries, storage is considered as both a consumer and producer and thus it is assumed that pumped storage would pay all the taxes and surcharges applied both to producers and to consumers.

55. First, there are PSOs for RES in every country of the benchmark. However, pumped-hydro storage facilities are exempted from these charges in Germany (exemption from EEG & CHP[28]), Austria[29] and Great Britain. However, as the regulation is not clear in Germany regarding the status of pumped storage, it is assumed that it has to pay some of the PSOs for RES, more precisely the Offshore Liability Levy.

56. Second, pumped-hydro storage is exempted from green certificates in Belgium and in Great Britain. In France and the Netherlands, green certificates do not exist. Therefore, green certificates are paid by the modeled facility in Austria only.

57. Belgium and Germany apply other PSO surcharges to electricity consumers. In Germany, a surcharge is applied in order to compensate the tariff reductions implemented for large industrial and storage facilities: the Stromnev Levy. In Belgium, a PSO must be paid by pumped storage facilities for the constitution of the strategic reserve.

58. In France, the CSPE tax includes PSO for RES, other PSO and is included in the category PSO for RES in the study. The CSPE is a tax in euros per MWh consumed, but is capped at 627 683 euros by year[30]. The electricity tax/levy is not paid in Germany and Austria because the law in these countries exempts pumped storage facilities from these charges[31]. Finally, an electricity tax is paid in the Netherlands.

59. Table 3 summarizes the taxes and levies that are paid by the pumped storage facility in the simulations.

[28] See https://www.amprion.net/Dokumente/Strommarkt/EEG/EEG-2017-Juris-Stand-13102016.pdf
[29] See https://www.e-control.at/en/marktteilnehmer/strom/strommarkt/preise/steuern-und-abgaben
[30] Given the fact that under this cap, the rate is 18.3 euros per MWh, it is assumed that the modeled pumped-hydro storage facility pays the maximum amount of CSPE.
[31] See https://www.e-control.at/en/marktteilnehmer/strom/strommarkt/preise/steuern-und-abgaben for Austria

Table 3. Summary of taxes and surcharges in the study

	PSO for RES	Green Certificate	Other PSO	Electricity tax/levy
Austria	Exempted	YES	NO	Exempted
Belgium	YES	Exempted	YES	Exempted
France	YES (CSPE)	NO	NO	NO
Germany	Exempted from EEG & CHP levy – Paying offshore liability	NO	YES	Exempted
Great Britain[32]	Exempted	Exempted	Exempted	Exempted
Netherlands	YES	NO	NO	YES

2.3 Revenues from the day-ahead market (DAM)

60. A first stream of revenues for a storage plant lies in the arbitrage in the energy market: the plant will pump during hours with low prices and produce during peak hours, thus earning the spread between those two extremes. In this study, only the day-ahead market is considered for this arbitrage (for simplicity, the plant does not make any arbitrage on the intraday prices or on the balancing mechanism price).

61. The designs of day-ahead markets are very similar in the studied countries. Moreover, these markets are interconnected and coupled, resulting in price convergence except when transmission lines are congested. For instance, prices are the same in France, Belgium, the Netherlands and Germany during 35% of the time in 2017. For Austria and Germany, a same day-ahead price is defined. This price convergence tends to reduce differences between countries (in particular revenues that can be earned on the day-ahead market), all other things being equal.

62. However, during hours when a price convergence is not reached, the day-ahead price can be significantly different between countries, reflecting different characteristics of demand and supply (for instance the significant production of cheap renewables in Germany). To compare these countries qualitatively and give some insights on the arbitrage that can be made on the day-ahead market, it is possible to study the average daily day-ahead market price spread, i.e. the average difference between the lowest and the highest day-ahead prices for each day. Indeed, given the size of the water reservoir considered for the studied PHS plant, a daily arbitrage is the most likely: the plant will withdraw electricity during the night when prices are low and will produce a few hours later during peak hours. Since the reservoir can store up to five hours of production at its maximal output, the five lowest and highest prices for each day are considered. In other words, it is assumed that the plant withdraws at its maximum capacity during the five hours with the lowest prices. Afterwards, it empties its reservoir by producing at its maximum output during the five hours with the highest prices for the same day. This average price spread between the highest and lowest values can then be computed.

[32] As the British regulation is not clear about the status of pumped storage facilities, we asked Engie UK what kind of consumption charges are paid by such facilities. They answered that pumped storage is considered as a generator and thus does not pay consumption taxes (i.e. Renewable Obligation Certificate, Climate Change Levy and the AAHEDC).

63. This average value can be interpreted as an indicator of the revenues the PHS plant can earn on the day-ahead market with a 100% efficiency[33] as well as perfect foresight, and if this plant does not incur any costs to produce or consume except the cost of bought electricity (in particular network costs are not considered). The average values for 2017 are summarized in table 4.

Table 4. Average daily day-ahead prices spread for 2017

	AT	BE	DE	FR	GB	NL
€/MWh	24.0	27.1	24.0	23.7	26.9	22.0

Source : Electrabel ; Calculation : Deloitte – Economic Advisory

64. These spreads give insights on the revenues that the plant could make on the day-ahead market theoretically when networks costs and surcharges are disregarded. Based on these values, potential profits resulting from the day-ahead price arbitrage and without considering any costs are quite similar for France, Germany and Austria. This arbitrage seems more advantageous for Belgium and Great Britain while the Netherlands have the lowest average daily spread.

65. However, this qualitative comparison cannot imply any conclusions on the revenues that storage plants can make on the day-ahead market since variable networks costs and surcharges can deeply modify the arbitrage decisions and the revenues that can be earned on the day-ahead market.

2.4 Revenues from the capacity remuneration mechanism (CRM)

66. CRMs have been implemented in several European countries to solve the adequacy issues. These CRMs aim at creating new revenue streams for power plants to help them recover their costs, and then prevent them from closing and/or incentivize investments. In particular, in the studied countries, two types of CRMs are already in place or will be implemented for 2018: 1) the strategic reserve mechanism in Belgium and in Germany and 2) the capacity market in France and in Great Britain. In the Netherlands and in Austria, there is no CRM. Revenues earned thanks to these mechanisms and considered in this study are summarized in Table 5.

Table 5. Considered revenues from the capacity remuneration mechanism

	AT	BE	DE	FR	GB	NL
€ million per year for a 1000-MW plant	0	0	0	7.1	20.9	0

Source : EPEX and National Grid ; Calculation : Deloitte – Economic Advisory

67. With the strategic reserve mechanism, the TSO procures and remunerates some power plants or demand response (the strategic reserves) which are kept available to produce during peak hours in order to avoid shortages. Once these plants become contracted by the TSO, they cannot produce on the energy market except during peak hours when required by the TSO. As a result,

[33] The numbers presented here for 100% efficiency are purely illustrative. One cannot presume from them the conclusions from the quantitative benchmark in section 3, for which the actual realistic efficiency assumptions for a PHS plant were considered (75% yield – linked to loss of energy when the plant withdraws from the grid and then injected again).

they are generally old plants whose costs cannot be covered by profits made on the energy market and would have been decommissioned otherwise. Then, it does not seem relevant to consider that a storage facility would forego likely profits on the energy and ancillary markets to be part of the strategic reserves. Therefore, revenues that the considered storage facility can earn with a strategic reserve mechanism are considered null in Germany and in Belgium.

68. In France and in Great Britain, a capacity market is implemented. Capacity providers, such as power plants or demand response, receive a new revenue based on the capacity price, determined thanks to the intersection of the capacity demand and supply, and based on the capacity the provider can guarantee to be available to produce during peak hours (in exchange of the capacity revenue, the power plant has to be able to produce during peak periods when required by the TSO; otherwise, penalties are applied[34]). Contrary to the strategic reserve mechanism, a power plant can both receive the capacity price and participate to the energy market.

69. Capacity revenues considered in this study are based on results for 2018. More details about their computation (in particular the considered derating factor of the storage facility) are described in appendix. In Great Britain, for a 1,000-MW storage plant, these revenues are considered equal to € 20.9 million per year whereas they reach € 7.1 million per year in France.

70. Theoretically, the existence of a capacity market should reduce the energy price spikes since market players do not need to cover their missing money through higher energy prices (they can cover it thanks to the capacity revenues). Consequently, revenues earned from the arbitrage on the energy market may be lower when a capacity market is implemented. For France, this impact is considered in the quantitative results since the capacity market was already in place for 2017 (day-ahead prices considered for the simulation already consider this impact, if exists). For Great Britain, the first year concerned by the capacity market is 2018/2019, therefore revenues from the energy market may be lower only from that date. However, this reduction is difficult to forecast, in particular in an interconnected power system.

71. In any case, it should be noticed that the implementation of a capacity market, even if it may decrease the revenues on the energy market, provides a more steady revenue for market players. Indeed, instead of earning very high profits from the energy market during very few hours for some years only (for instance during a cold wave) to cover part of their fixed costs, market players earn more steady revenues, both coming from the energy market and the capacity market. A capacity market is then more attractive for investors since related revenues are less risky and volatile.

2.5 Revenues from the ancillary services

72. Main ancillary services generally include:

    a. Frequency control reserves

    b. Voltage support

    c. Black start

[34] In the simulations, it will be considered that the plant is always available and thus does not pay any penalty.

73. Given their high flexibility, PHS facilities are assumed able to provide all these services from a technical point of view (these technical requirements are explained for frequency control reserves in the section 3.1 detailing the methodology for quantification).

74. These ancillary services, the way the TSO procures them and their remuneration are compared hereafter for each country (and in more details in appendix). A focus is made on the frequency control reserves which are key for the stability of the power systems and which can constitute a significant part of the revenues for a storage facility, which can monetize its high flexibility on the associated reserves markets.

2.5.1 Frequency control reserves

75. Reserves used to maintain the balance between generation and consumption are essential in current power systems. Moreover, these reserves products tend to become more and more harmonized across Europe regarding their activation time, which makes the comparison between countries easier (as well as the modeling as presented thereafter). In particular, according to the nomenclature of ENTSO-E, four different types of frequency reserves can be distinguished in Austria, Belgium, France, Germany and the Netherlands, namely:

    a. The Frequency Containment Reserves (FCR), activated in less than 30 seconds;

    b. The automatic Frequency Restoration Reserves (aFRR), activated between 30 seconds and 15 minutes;

    c. The manual Frequency Restoration Reserves (mFRR), whose activation time is generally equal to 15 minutes;

    d. And the Replacement Reserves (RR), whose activation time is higher than 15 minutes.

76. The situation in Great Britain is much more complex since more than ten different products exist with different technical requirements (cf. appendix 5.5.4). Moreover, to the best of our knowledge, data about the past remuneration of these products are not available in the current literature (or very sparse). These prices are essential for the quantitative study made in the following chapter. For these two reasons, the study of the frequency reserves is not made for Great Britain. In the following sections, characteristics of the frequency reserves in Austria, Belgium, France, Germany and the Netherlands only are described and compared.

77. Moreover, in the following sections, and as it will be explained in the section 3.1, only the remuneration of the reserves procurement (and the associated technical constraints) is compared. To simplify, the remuneration of the actual activations is not considered in this study.

78. Three interesting features of reserves products are worth being mentioned to compare qualitatively revenues that the storage facility can earn on these markets:

    a. The **characteristics of the reserves products**: the provision of frequency reserves will constrain the functioning of the power plant (for instance, to provide upward reserves, the plant cannot produce at its maximum output; to provide FCR, it has to be already online to be able to react quickly. These technical requirements will be explained in the modeling section). The characteristics of the reserves products can imply more or less stringent constraints. In particular, three characteristics are studied and compared qualitatively below:

        i. The **contract duration of reserves products** (hour, day, month…): all other thing being equal, it is more constraining to provide reserves for a whole month than for one day. For instance, with a monthly product, the plant has to ensure that it is able to

provide these reserves for each hour of this month. If the plant has to be online to provide these reserves (as it is the case for aFRR or FCR – cf. modeling section 3.1), it means that the plant has to be online for a whole month, even during off-peak hours. If daily products are used, the plant has more flexibility to decide when it wants to provide reserves since it has to be online during 24 hours only. For instance, this plant can decide to provide reserves only during weekdays.

ii. The **symmetry (or asymmetry) of reserve products**: depending on the country, reserves providers have either to provide asymmetric reserves (i.e. upward or downward) or symmetric products (both upward and downward). All other thing being equal, a symmetric product increases the constraints that the plant has to fulfil.

iii. The **activation constraints**: contracted plants have to be able to produce if reserves are activated by the TSO. Consequently, a storage plant has to have enough water in its reservoir if it provides upward reserves, then constraining the functioning of the plant. Depending on the countries, some limits on the maximum number of hours these reserves can be activated are enforced. These limits reduce the volume of water that the plant has to keep available[35].

b. The **market size**: the higher the demand of the TSO, the larger the volume that can be provided by power plants and then the higher their revenues can be.

c. The **procurement price**: the higher the remuneration of the reserves procurement, the higher the revenues for the storage facility. Moreover, a pay-as-cleared remuneration (opposed to pay-as-bid) tends to increase the profits the plant can make[36].

Frequency Containment Reserve (FCR)

79. All studied countries (except Great Britain) have harmonized the characteristics of the FCR product and the way they procure it. A common FCR market has been created between these countries to enable the TSOs to procure FCR at minimum cost. This harmonization and the common auction reduce the difference between countries and the associated remuneration. Moreover, thanks to this common market, reserves providers can now offer their services abroad (for instance, a Belgian producer can provide FCR for the German TSOs), then increasing the size of the market they can reach. However, the volume they can provide abroad is limited due to congestions on transmission lines.

80. Table 6 summarizes the main characteristics of the FCR products.

[35] Regarding the activation constraints, the activation time (i.e. how fast reserves have to be able to change their output) could also be studied. However, for the studied countries (except Great Britain which is out of the scope of quantification of revenue from ancillary services) and the studied products, this activation time is quite similar between countries. Moreover, given the high flexibility of the PHS facility, any slight difference in the activation time between countries should not result in different reserves abilities. Then, this characteristic is not studied and compared below.

[36] With a pay-as-bid rule, market players try to forecast the market-clearing price and will bid at this price (and not at their marginal costs). If their forecast is right, they will earn the market clearing price. With a pay-as-cleared rule, they will bid at their true marginal costs and will always earn the market clearing price. In case of perfect information, both solutions result in the same outcomes and revenues. However, without this assumption, a pay-as-cleared rule is better since market players do not have to forecast the market clearing price. They will always earn the market price without the risks of making wrong forecasts.

Table 6. Qualitative comparison of the FCR product

		AT	BE	DE	FR	NL
Temporal resolution of the reserves product		One week				
Symmetric or asymmetric		Symmetric				
Maximum duration of activations		To the best our knowledge, there is no maximum value (reserves can be activated during the whole duration of the product).				
Average market size for 2017 (MW)	Common European auction	162	130	784	729	174
	National auction	/	18	/	/	33
Average price for 2017 (€/MW.h)	Common European auction	14,6				
	National auction	/	33,1	/	/	14,9
Remuneration rules		Pay-as-bid				

Source : regelleistung.net and national TSOs; Calculation : Deloitte – Economic Advisory

81. Several interesting differences can be mentioned based on this qualitative comparison:

    a. Whereas France, Germany and Austria procure all their needed FCR thanks to the common auction, the Belgian and Dutch TSOs procure part of their FCR need through national procurement.

    b. Higher volumes are procured in France and Germany (because of their higher national consumption). Even if services providers can offer reserves abroad, this export is limited due to congestion constraints[37]: a Belgian plant can then provide services for Germany (increasing the market size it can reach) but to a limited extend.

    c. Due to the common auction, prices are the same in all countries except for the national products previously mentioned. In particular, the remuneration of the Belgian national FCR product is higher due to more constrained technical requirements (cf. appendix 5.2.4). However, the demand of the Belgian TSO for this product is low, limiting possible revenues earned on this market and then differences with other countries.

    d. Finally, characteristics of the contracted products are similar in all countries.

Automatic Frequency Restoration Reserve (aFRR)

82. For the aFRR product, harmonization between countries is less advanced (in particular there is no common auction), resulting in several differences for the remuneration or the characteristics of the traded products. Table 7 summarizes the main characteristics of the aFRR products.

[37] Cf. https://consultations.entsoe.eu/markets/fcr-cooperation-potential-market-design-evolutions/supporting_documents/20170102%20FCR%20market%20consultation.pdf

Table 7. Qualitative comparison of the aFRR product

		AT	BE	DE	FR	NL
Temporal resolution of the reserves product		60 hours[38] or 108 hours[39]	One week	60 hours[38] or 108 hours[39]	One hour	One month, one quarter or one year
Symmetric or asymmetric		Asym.	Asym.	Asym.	Sym.	Sym.
Maximum duration of activations		To the best our knowledge, there is no maximum value (reserves can be activated during the whole duration of the product).				
Average market size for 2017 (MW)	Up.	200	144	1,836	13 (up. and down.)	340 (up. and down.)
	Down.	200	144	1,906		
Average price for 2017 (€/MW.h)	Up.	1.8	13.8	2.5	18 (up. and down.)	19.8 (up. and down.)
	Down.	3.6	13.8	0.8		
Remuneration rules		Pay-as-bid			Regulated price	Pay-as-bid

Source : ENTSO-E and national TSOs; Calculation : Deloitte – Economic Advisory

83. Among the main differences, it can be mentioned that:

a. Procurement of aFRR in France is quite different from other countries: producers connected to the transmission grid have an obligation to provide some reserves. The hourly volume they have to provide is determined by the TSO based on its expected production (in particular, if the plant is not expected to be online, it does not have to provide some reserves). Consequently, the plant cannot choose the volume it wants to provide. Based on the size of the studied plant (1000 MW), the plant must provide up to 13 MW. Moreover, the corresponding remuneration is regulated.

b. German TSOs procure a large volume of aFRR, due to the size of the German power system. If profitable, the plant can then provide a large volume and earn more than in other countries, all other things being equal.

c. Regarding remuneration price, they are well higher in Belgium and in the Netherlands[40].

d. Finally, regarding the characteristics of the aFRR products, Germany and Austria appear to use more granular products, which improves the participation of the power plant. For instance, the plant can decide, if profitable, to provide upwards reserves only for a reduced number of hours (60 hours for peak products) whereas it has to commit for longer periods in Belgium or the Netherlands (up to one year in the Netherlands).

[38] These 60 hours correspond to the time frame 8 a.m.-8 p.m. for the five weekdays of one week.
[39] It corresponds to the time frame 12 a.m.- 8 a.m. and 8 p.m. – 12 a.m. for the five weekdays of one week and the whole weekend.
[40] France is a specific case since procurement of aFRR is compulsory.

Manual Frequency Restoration Reserve (mFRR)

84. Like aFRR, harmonisation of mFRR procurement markets is limited in the studied countries. Table 8 summarizes the main characteristics of the mFRR products.

Table 8. Qualitative comparison of the mFRR product

		AT	BE	DE	FR	NL
Temporal resolution of the reserves product		4, 8 or 20 hours[41]	One month	4 hours	2 days or 5 days[42]	6 months or one quarter
Symmetric or asymmetric		Asym.	Asym. (up. only)	Asym.	Asym. (up. only)	Asym.
Maximum duration of activations		No maximum value[43]	- Std[44] prod: 8h/day - Flex prod: 2h/day	No maximum value[43]	1, 2, 3 or 4 hours/day[45]	No maximum value[43]
Average market size for 2017 (MW)	Up.	280	- Std Prod: 305 - Flex Prod: 315	1,318	1,000 MW which can be activated during 4 hours a day[46]	350
	Down.	170	/	1,717	/	200
Average price for 2017 (€/MW.h)[47]	Up.	2.2	- Std Prod: 4.3 - Flex Prod: 3.4	0.1	2.8 for a maximum activation of 4 hours/day[48]	4.8
	Down.	2.8	/	0.8	/	10.7
Remuneration rules			Pay-as-bid		Pay-as-cleared	Pay-as-bid

Source : ENTSO-E and national TSOs ; Calculation : Deloitte – Economic Advisory

85. Based on this qualitatively comparison, it can be said that:

[41] Cf. appendix 5.1.4 for more details
[42] Weekend products are procured for two days whereas weekdays products are procured for five days.
[43] To the best of our knowledge given the current documentation.
[44] Std=Standard
[45] The French TSO wants to procure 1,000 MW that can be activated during 4 hours a day. However, market players can submit bids with a lower constraint for the maximum duration of activations (for instance, a plant can submit a volume of 200 MW but it commits to be activated only during one hour a day). The TSO then chooses the cheapest bids to reach its need. For instance, instead of procuring one expensive bid of 1,000 MW which can be activated during 4 hours a day, the French TSO can procure 2 bids of 1,000 MW each and which can be activated during 2 hours only a day. Remuneration of each bid is adjusted according to the maximum duration of activations the plant submits (a 100-MW bid with a 4-hour constraint for activation will earn more than a bid for the same power but which can be activated only 2 hours a day).
[46] The TSO can contract more than 1,000 MW if plants submit bids with a lower activation constraint. The need of the TSO can be defined as having at least 1,000 MW of mFRR and 4,000 MWh of energy per day.
[47] For France, the average marginal price is given (since a pay-as-cleared remuneration is used).
[48] If the plant commits to be activated during less hours, its remuneration decreases. For instance, for a commitment of activations during 2 hours a day, the average price is about 1.5 €/MW.h.

a. Characteristics of mFRR products (beyond the activation time which is similar) well differ from country to country. In particular, Germany, Austria and the Netherlands procure both upward and downward reserves whereas France and Belgium procure upward products only.

b. Regarding remuneration prices, they are very low in Germany compared to other countries. In particular, the remuneration of upward reserves is almost zero on average: the storage facility will not be incentivized to provide these reserves in this country. Moreover, in France, procurement is remunerated using a pay-as-cleared rule contrary to all other countries.

c. Regarding the temporal characteristics, the German and Austrian TSOs use very granular products defined on 4 hours only. If a plant wants to provide reserves, it can do so for only four hours, then reducing the associated technical constraints. On the contrary, in Belgium, plants have to commit for a whole month and even longer in the Netherlands. In these countries, provision of mFRR will highly constrain the functioning of the power plant all other things being equal.

d. Finally, regarding the maximum duration of activations, to the best of our knowledge, there is no maximum limit for Germany, Austria and the Netherlands. Reserves can then be activated for four consecutive hours in Germany and Austria, which constrains the water the plant has to keep in its reservoir. On the contrary, France and Belgium have a maximum number of hours for activations. A storage facility with a limited reservoir size can then more easily provide mFRR products in Belgium (with the flex product) and in France (power plants can keep a lower volume idle in the reservoir and use the remaining volume for other services, in particular for the arbitrage on the day-ahead market).

Replacement Reserve (RR)

86. The French TSO is the only one to procure RR. This product shows some similar characteristics with the French mFRR product, in particular regarding the limited number of hours when reserves are activated. Compared to other countries, it offers an additional stream of revenues for the storage facility (providing it is profitable for the plant to provide this service). Characteristics of this French product are summarized in Table 9.

Table 9. Qualitative comparison of the RR product

	AT	BE	DE	FR	NL
Temporal resolution of the reserves product	/	/	/	2 days or 5 days[49]	/
Symmetric or asymmetric	/	/	/	Asym. (up. only)	/
Maximum duration of activations	/	/	/	1, 2 or 3 hours/day	/
Average market size for 2017 (MW) Up.	/	/	/	500 MW which can be activated	/

[49] Weekend products are procured for two days whereas weekdays products are procured for five days.

		AT	BE	DE	FR	NL
					during 3 hours a day[50]	
Average price for 2017 (€/MW.h)[51]	Up.	/	/	/	1.9 for a maximum activation of 3 hours/day[52]	/
Remuneration rules		/	/	/	Pay-as-cleared	/

Source : ENTSO-E and national TSOs; Calculation : Deloitte – Economic Advisory

87. To summarize the qualitative comparison of possible revenues from the provision of frequency reserves, it appears that, except for FCR products, products traded in each country show many differences regarding the contracted volume, the price or the characteristics of the products (in particular the temporal duration). Consequently, it is impossible to conclude and to compare revenues that each plant can make with these provisions based on the qualitative comparisons only. For example, power plants can provide a large volume of mFRR in Germany since the volume required by the TSO is high and since the products are highly granular (on 4 hours only and asymmetric). However, the associated price is very low, making this product less advantageous. On the contrary, mFRR products in Belgium tend to be highly remunerated but power plants have to commit for a whole month, which may constrain their functioning and then reduce the revenues they can make on other markets. A quantitative analysis is then essential to give clear insights regarding the revenues that a PHS facility can earn thanks to the provision of frequency reserves in each country.

2.5.2 Voltage support

88. Contrary to the previously studied frequency control reserves, voltage control reserves are less extensively documented in the literature and in the available documents published by the TSOs. In particular, the remuneration of these services is often not published due to confidentially issue. Moreover, voltage support products are less harmonized from a technical point of view than frequency control reserves, which makes the direct comparison more difficult between countries.

89. Voltage support is an obligation for large power plants in most of the studied countries (cf. appendix for more details). This obligation is nevertheless always remunerated, either with a regulated price or a free price. In countries where the provision of voltage support is not compulsory, plants are free to provide this service and are remunerated for it.

90. Regarding the remuneration price, the available literature does not enable to compare profits that each plant can make with this service for each studied country. Furthermore, the technical requirement to provide voltage support can be slightly different from country to country (the voltage control reserves are not harmonized like the frequency control) and then the costs to provide this service can be hardly compared.

91. Consequently, in this study, it is considered that in each country, the remuneration of the voltage support provided by the plant (either voluntarily or compulsorily) is equal to its opportunity costs. This 'cost-plus' vision of black-start and voltage support remuneration seems reasonable

[50] The TSO can contract more than 500 MW if plants submit bids with a lower activation constraint. The need of the TSO can be defined as having at least 500 MW of RR and 1,500 MWh of energy per day.
[51] For France, the average marginal price is given (since a pay-as-cleared remuneration is used).
[52] If the plant commits to be activated during less hours, its remuneration decreases. For instance, for a commitment of activations during 1 hour a day, the average price is about 0.6 €/MW.h.

according to Electrabel's teams; it should only impact marginally the order of magnitude of the results[53]. Then, revenues that the plant can earn thanks to the voltage support are null and the same for all countries.

2.5.3 Black start

92. Like voltage support, black start services are not well documented in current publications of TSOs. The associated remuneration is often undisclosed and the technical requirements to provide this service differ by country. Comparisons of revenues resulting from the provision of black start services are then limited.

93. In all countries but France, this service is voluntarily and remunerated. In France, this service is compulsory for some generation plants and non-remunerated. In particular, to the best of our knowledge, black start obligations concern hydropower units. Like for voltage support, in countries where this service is remunerated, it is assumed that this remuneration is equal to the opportunity costs to provide it. Consequently, associated revenues are zero[54].

[53] This also seems aligned with the Belgian approach regarding remuneration of those services. In 2015, the CREG assessed that prices submitted by some offers were unreasonable. As a result, the Ministry of Energy published decree projects that would fix volume and price conditions. See the CREG's opinion for these projects here: http://www.creg-ar.be/2015/images/pdf/CREG-AR-2015_fr_%C3%A9lectricit%C3%A9.pdf

[54] Note that for France, there are no possibility for (positive) revenues, but the PHS incurs cost linked to the obligation to provide uncompensated black start. To evaluate this cost, the remuneration of the black start service currently provided by the power plant of Coo in Belgium is used. This value was communicated by Electrabel.

3 Findings from the quantitative benchmark

94. The quantitative benchmark enables to simulate the behavior of a modeled PHS plant with varying assumptions regarding its regulatory and fiscal framework as well as the characteristics of the different revenue streams (prices, volumes, conditions for participation…). It assesses and compares the theoretical levels of PHS gross margin which can be reached in each country.

95. As a reminder, several types of quantitative simulations (or scenarios) are carried out for several perimeters (see table 1 in section 1.2). The main set of simulations model the behavior of PHS plants when they are able to participate to energy markets and on CRMs only, for year 2017. Other simulations and sensitivity analyses enable to appraise the following elements:

- The *marginal*[55] impact on margins and revenues of the national regulatory and fiscal rules, all other things being equal
- The *marginal* impact on margins and revenues of an eventual tariff exemption in Belgium
- The *marginal* impact on margins and revenues of the possibility to participate to ancillary services, with a separate assessment of aFRR, mFRR and RR on the one hand, and FCR on the other due to computation limitations.
- The variability of volumes and margins from one year to another, due to the high volatility in energy prices

96. The section is divided into two parts. Firstly, the methodology for simulations and quantification is described along with the main assumptions. Secondly, results for the main simulations sets are described and analyzed. Additional results are also described and analyzed in appendices 5.8 and 5.9.

3.1 Details on the methodology for quantification

3.1.1 Introduction

97. This section aims at explaining the method of simulation used with a view to understand how the results of the quantitative benchmark were obtained. It also emphasizes the limits of the method and their potential consequences on results.

98. The simulations seek to compute revenues and costs of a PHS (Pumped Hydro Storage) into different countries, i.e. with different regulations, market design, prices, tariffs and taxes.

99. For each country, the PHS plant seeks to maximize its gross margin given the countries' different markets and regulatory and fiscal frameworks (tariffs, taxes …) by making the most profitable decisions regarding its production, its consumption and the procurement of ancillary services (in sensitivity analysis). The simulation thus results in an **optimization problem** with a **plant considered as rational from an economic point of view**. For each country, the optimization is performed **with a one-hour time step for the 8760 hours of a year** based on **historical data for prices (for the day-ahead market, remuneration of ancillary services…) and**

[55] Marginal impact is here meant in the sense of incremental: it is the differential effect that a new assumption (possibility to participate to ancillary services, tariff exemption…) can have on the simulation's outputs.

volumes (for the demand of ancillary services). **The plant is considered as price taker**: the plant's decisions (regarding production, consumption, provision of ancillary services) do not affect realized prices[56]. Also, as the optimization is run for all 8760 hours at once, **the plant is considered as omniscient** and knows in advance prices for the whole year: it performs a **perfect foresight optimization**. Those two assumptions are very common in the academic literature but have a consequent impact on results, as reality is quite different. Indeed, given uncertainties and its impact on prices, the plant can get only a portion of this perfect foresight profit. The interested reader can refer to the box dedicated to perfect foresight in part 3.1.3. Hence, the resulting gross margin is an **idealized gross margin**.[57]

100. To sum up, the simulation represents a rational omniscient PHS plant seeking to maximize its idealized gross margin.

3.1.2 PHS description

101. All parameters below are input data given by Electrabel.

102. The PHS at stake is identical for each country considered.

a. The plant considered has **5 reversible turbines** (each turbine can either pump (withdraw electricity from the grid) or produce (inject electricity to the grid)) of **200 MW of maximum capacity each, resulting in a global maximum capacity of 1000 MW**.

b. Those turbines have also a minimum power when producing of 80MW.

c. Moreover, **it is impossible to modulate power when pumping**, hence if a turbine is pumping its consumption is necessarily equal to 200 MW.

d. A **global yield of 75% is assumed.**

e. The **maximum stock of water (common to all five turbines) corresponds to 5000 MWh** being injected to the grid (about 5 hours of production at the maximum output).

f. The plant is always available, there is no maintenance need or risk of breakdown for the whole year.

g. Start-up costs are considered individually for each turbine. Start-up time and ramping constraints are also considered in this modeling.

h. In addition, variable costs other than those related to network-related costs and buying energy in the DA market are not considered.

103. It is important to note that hydraulic bypass is enabled: one turbine can be in production mode while the others are pumping. As is highlighted thereafter, this assumption is key for the plant to provide reserve. One should be aware that not all power plants are able to perform bypass. This assumption is very optimistic and does not describe the overall reality of pumped storage in Europe. As a result, the results of the simulations when participation to reserves is

[56] In addition, we do not consider the possibility of paradoxically rejected offers. In reality, a PHS plant can sometimes see its bids even if the proposed price is below the clearing price. For example, if the system needs an additional 50MW and that a PHS plant bids with a minimum power of 100MW, its bid will not be accepted regardless of its price.
[57]

allowed are extreme. They only illustrate a sensitivity analysis of the maximal profitability PHS could reach thanks to ancillary services[58].

104. The plant is considered on its own, as opposed to part of a portfolio. This implies that when providing reserves, the plant cannot rely on other assets to respect its commitment (for instance, when reserves are defined on a monthly basis, the plant commit to provide these reserves for the whole month).

105. The plant is supposed to have recently invested in expansion of their stock or turbine output. The expansion fulfills at least the criteria to benefit from the tariff exemption in Germany for plants built before 4 August 2011[59].

106. A complete description of the plant represented in the simulation is available in appendix 5.7.

3.1.3 Revenues considered in the optimization problem

107. For each country, the simulation includes revenues for the following markets:

a. Capacity Remuneration Mechanism (CRM)

b. Day-ahead market (DA)

c. Frequency reserve markets

i. Frequency Containment Reserve (FCR, R1 in Belgium)

ii. Automatic Frequency Restoration Reserve (aFRR, R2 in Belgium)

iii. Manual Frequency Restoration Reserve (mFRR, R3 in Belgium)

iv. Replacement Reserve (RR, for France only)

108. Thus, the simulation excludes the following: voltage regulation, black start services, intraday market, balancing mechanism. Those are excluded because of the lack of publicly available data.

109. For reserves, **the simulations consider only the revenue from procurement**. They do not take into account the actual activations of these reserves. Still, the simulation imposes to the plant to be capable to deliver what it has contracted at every time step. Resulting constraints are detailed in the next section.

110. Regarding the maximum volume that the plant can contract for each reserve, it is assumed that it can contract up to the total volume of the country (plus the volume that can be exported to other countries for FCR). This assumption is very optimistic for ancillary services and does not describe the overall reality of pumped storage in Europe. Along with hydraulic bypass, this is one of the main assumptions explaining why the results of the simulations when participation to

[58] It should be noted that not enabling hydraulic bypass for a plant without a portfolio would have most probably led to the PHS plant not providing any reserve in most countries ; such a result would have not been realistic either and would have prevented any sensitivity analysis and comparison.
[59] Therefore, one assumes for the benchmarks and the simulations a plant, identical in each country, built before 4 August 2011 and having recently expanded its reservoir size by at least 5% or its turbine output by at least 7.5%. This assumption is aligned with the observations in Germany, where most old PHS plants have been refurbished to benefit from the exemption.

reserves is allowed are extreme. They only illustrate a sensitivity analysis of the maximal profitability PHS could reach thanks to ancillary services.

111. As for the costs, the plant pays in each country the corresponding transmission network charges, taxes and surcharges applied.

Box 1. Considering reserve activations: an insight from the literature

Only a few papers focusing on storage consider both arbitrage on DA market as well as procurement of frequency services. Among those papers, none considers fully the activation of reserve. This can easily be understood as activations depend of the state of the whole electric system and are very difficult to take properly into account. In (2017, T. Brijs)[60], activation is not considered at all and no stock is reserved in the event of an activation (it is assumed that a plant can provide upward reserves even if its reservoir is empty). In (2016, Asmae Berrada et al.)[61] activation is considered as a continuous process. A ratio δ in percent is calculated for each reserve *ex ante* based on historical date. It is computed as the total volume contracted during the year divided by the total volume activated (δ is between 0 and 100%). Each hour, the simulation considers that δ% of contracted volume provided by the plant is activated. This activation then results in a payment[62] from the TSO as well as a reduction of the available stock (or an increase for downwards reserve).

Not considering the activation, as done in the simulation, is equivalent to considering than the payment from the TSO for the activation equals the cost for the plant to refill its stock after an activation. Still, as the constraint for the stock is included, the plant does not provide any reserve it would not be able to supply (for instance if the reservoir is empty).

3.1.4 Simulation specificity

112. The following paragraphs details some technical aspects of the simulation aiming to represent operational constraints as close as possible to the real ones.

DA related constraints

113. It takes less than 20 minutes for a turbine to go from pumping to producing at full power (and vice versa). Hence, at an hourly time scale for the day-ahead market it is considered that there are not any ramping constraints for the plant. Thus, the functioning of the plant is only limited by turbines minimum and maximum power and its water stock.

CRM related constraints

114. When a capacity market is implemented, simulations consider that the plant is always available during peak hours to produce, resulting in the plant not paying any penalty associated to the CRM.

[60] 2017, T. Brijs, Electricity storage participation and modeling in short-term electricity markets.
[61] 2016, Asmae Berrada et al.,Valuation of energy storage in energy and regulation markets
[62] In case of downward reserve (i.e when the plants produce less than planned), it results in the plants paying the TSO. But what is paid is less than what was earned in the DA market for the energy sold, which is finally not produced. It still results in additional money for the plant.

Reserve procurement related constraints

115. As turbines cannot modulate their consumption when pumping, no reserve can be contracted on a turbine pumping.

116. The plant having to be able to provide the reserves it has contracted results in a constraint of robustness in power and energy:

a. Power: at every time step, given the arbitrage the plant is doing on the DA market, each turbine has enough power to provide, in addition to DA commitment[63], what is has contracted for reserve.

b. Energy: at every time step, the plant has enough stock to satisfy its DA commitments as well as all reserve contracted in the event of an activation.

FCR related constraints

117. To provide FCR, the response time is less than 30 seconds. Thus, given the startup time of the plant, a turbine can provide FCR only if it is already online (and then produce at least at its minimum output). Once on production mode and considering the very steep ramping rate of turbines, it is considered that the turbine can contract all its available power.

118. FCR is a symmetric product. It means for a 60 MW product for example, the plant should be able, if activated, to produce 60 MW more <u>or</u> 60 MW less than planned. Let us consider one turbine with a minimum power of 80MW and maximum power of 200 MW. To contract a 60-MW product of FCR, the turbine should produce at 140 MW, to be able to go 60 MW downwards (140-60 = 80 MW >= Pmin) or upwards (140+60 = 200 MW <= Pmax).

aFRR related constraints

119. Constraints related to the procurement of aFRR are similar to the one for FCR. However, aFRR products generally include upwards and downwards reserve, which is a facilitator for the plant. Indeed, for a 60-MW product of aFRR upwards, the turbine can produce between 80 MW and 140 MW.

mFRR and RR related constraints

120. To provide mFRR or RR, the response time is around 15 minutes for mFRR and higher for RR. Thus, an offline turbine is responsive enough to start and reach the required power.

121. mFRR reserves whose the maximum duration of activation is above two hours are not considered in the simulation. The reason for that is that the constraint on stock is too strict (for upward reserves, the storage facility has to keep available a large volume of water in its reservoir to be able to be activated by the TSO during several hours), resulting in other production means than PHS (such as Open Cycle Gas Turbines) are more cost-effective to provide those reserve.

[63] For upwards reserve, it means being able to produce more (or consume less) than planned in the DA market while for downward reserve it means producing less (or consuming more) than planned in the DA market.

3.2 Analysis of the results from quantitative benchmarks

122. The remainder of the section presents the main results obtained from the quantitative benchmarks, for year 2017. As a reminder, the main set simulates the plants' behaviors only on DA and CRMs, because modeling constraints prevent from modeling the behavior on ancillary services with the same level of precision and fair comparability than on the day-ahead and on CRMs. The sensitivity analyses for years 2015 and 2016, and the theoretical assessment of profitability levels considering the capacity to participate to reserves are presented in appendices 5.8 and 5.9.

123. The described and analyzed results mostly consist of the aggregation and/or comparison of the quantitative elements listed hereafter.

- The **cumulated costs incurred** by the modeled storage plants during the simulated year(s), resulting from its behavior and decisions on the different markets and remuneration mechanisms it can access. Those costs are distributed between (i) **cost related to pumped energy and start-up cost** of turbines and pumps, (ii) **taxes and surcharges** and (iii) **transmission related costs**. Note that the other operating costs linked to the day-to-day operation and maintenance of the plant (personnel, overhead …) and the investments costs are not included in the main quantitative results. Indeed, they are considered equal between all countries to ensure a level-playing-field comparison, with identical plants and identical management of the plant in each country. However, the results will be analyzed with respect to the ranges for these costs, in order to draw first ideas on the actual profitability in each country.

- The **cumulated revenue** earned on the different markets and remuneration mechanisms that the modeled storage plants can access, for the simulated year(s). Revenue is distributed between: (i) **revenue earned on day-ahead** wholesale energy markets, due to the direct selling of stored energy on the markets, (ii) **revenue earned through the procurement of ancillary services** (in the sensitivity analysis in appendix)[64] and (iii) **revenue earned through CRMs**[65].

- At a technical level, the volumes of **energy withdrawn and injected** on the day-ahead wholesale market and the **maximal hourly withdrawals or injections** for the simulated year(s), resulting from the modeled storage plant's behavior and decisions on the different markets and remuneration mechanisms it can access.

[64] As a reminder, it is assumed that the net revenues from the provision of voltage support and of black start are equal to zero (cf. the qualitative benchmark) and there are not considered in the modeling for simplicity (for the provision of black-start in France, which is compulsory and non-remunerated, the associated cost is considered in the transmission related costs).
Moreover, for frequency reserves, the remuneration from their activations is not considered for the sake of simplicity. The volumes of activation requested to the plant indeed depend on several parameters, such as the imbalance trend of the whole system and the rules used by the TSO to activate reserves (merit-order, pro-rata…), which cannot be considered easily in the modeling. Moreover, it is difficult to assume that the plant can estimate correctly imbalances price in advance (the imbalances trend is already difficult to anticipate) and then optimize its production decisions knowing these prices. Finally, when non considering activations, potential revenues are disregarded in the simulations. However, these revenues are linked with associated costs which are also disregarded. For instance, if a procured PHS plant is activated upward by the TSO, it will earn from the upward activation but it has to pump more electricity afterwards (or produce less), resulting in costs.
[65] As explained previously, revenue earned through CRMs are calculated using values for 2018 (cf. the qualitative benchmark).

- At an aggregated level, one can compare the **net revenue on day-ahead** wholesale markets. This net revenue is easier to grasp than looking individually at the revenue and the costs (pumped energy and start-up costs) linked to the activities on the day-ahead.

- At an even more aggregated level, the (annual) **idealized gross margin** before operational and management costs is calculated as the difference between all listed costs and revenue categories. The idealized gross margin is a proxy for profitability, but the two are not equal. Indeed, as previously explained, gross margin is calculated before costs linked to day-to-day operations and maintenance, and before investment costs. Profitability (before income tax) could be easily extracted from gross margin by subtracting those additional costs, which are considered identical in all countries. The gross margin is also qualified as idealized because it is the optimized margin that the PHS plant could get in the ideal setting of the modeling. The actual gross margin should in theory be lower than in the simulations, where it is assumed that the PHS plant has perfect foresight and is completely omniscient to the future volumes and prices on the markets, and that resilience effects are not considered[66] (see box 2 in the next subsection for estimations of the impact of perfect foresight on the results).

124. In countries where several tariff (or fiscal) areas exist, and when relevant, the results are aggregated based on averages of all zones. This is the case for Austria (3 network tariff areas) and for Great Britain (the tariffs in all areas are first averaged for the three TSOs to feed the inputs, then the resulting outputs of the simulation for these TSOs are averaged – See appendix). For these countries, the following figures in the result description show the average as well as the minimum and maximum values.

3.2.1 Quantitative benchmark with day-ahead arbitrage and capacity remuneration mechanism

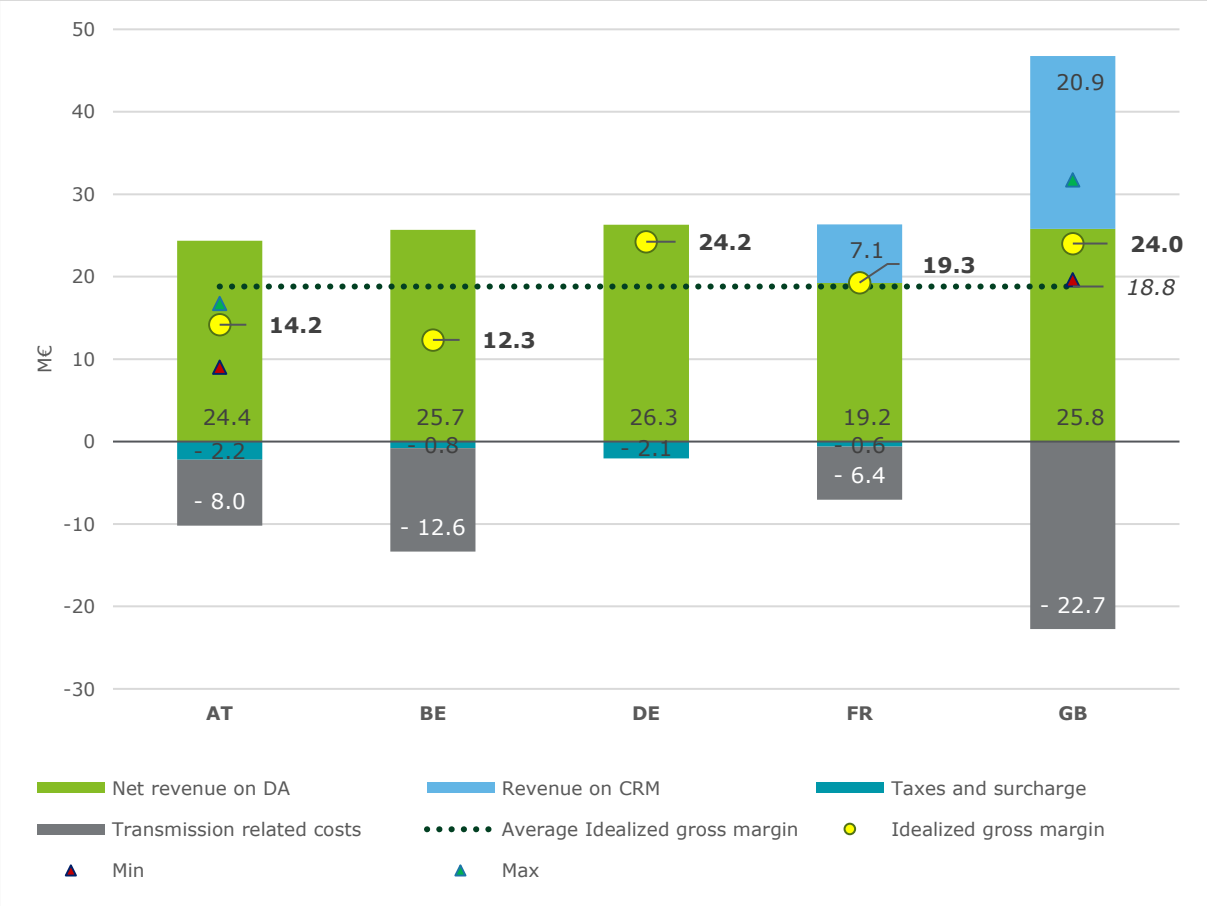
125. This subsection presents the results of the simulation of the modeled storage plant for the year 2017, assuming that the plant's operational choices and valuation options only include arbitrage on the day-ahead (DA) market and the (eventual) CRMs. This is the main simulation set, which enables the balance between a fair and reasonable comparison between countries and the use of simplified assumptions[67]. It should be reminded that those results only illustrate the relative levels of profitability from one country to another for a theoretical plant; absolute estimations of actual PHS profitability in a given country, for a given plant, should not be extracted from these values.

126. The modeled storage plant is simulated for Austria, Belgium, France, Germany and Great Britain (five countries). For each country, all market prices, rules and conditions and all regulatory and fiscal provisions considered in the simulation correspond to the actual national data. Luxembourg, while in the scope of the benchmark, was not studied individually because the Luxembourgian PHS plant (Vianden) is connected to the German network of Amprion. Besides, the analysis of drivers for the Netherlands was limited to the qualitative analysis and a comparison of transmission costs and taxes with the other countries: as the Dutch potential for PHS is null, its inclusion in the main comparison of preferences from an investor point of view does not make sense.

[66] During peak hours, the fact of producing will tend to decrease the actual day-ahead price since supply increases. Conversely, when the plant pumps during hours with low prices, the fact of consuming electricity will tend to increase the actual day-ahead price. Then, in reality, revenue from the day-ahead market will be lower since the plant buys electricity at a higher price than expected and sells it at a lower price than expected. Moreover, this resilience depends on the size of the market. In this study, it is considered that the power plant decisions do not modify the actual day-ahead prices.
[67] Given the assumptions made in the modeling (perfect foresight for instance). These assumptions and their impacts on the gross margin are discussed in Box 2.

127. It should be highlighted that the optimization problem solved includes integer variables. Thus and for computation time purposes, the results come with an uncertainty of + 200 k€[68].

Figure 3. **Comparison of idealized gross margins earned by the modeled PHS plant**



Quantitative benchmark – National markets – DA+CRM - 2017

128. As seen in figure 3 above, assuming that the storage plant can only participate to the DA market and to capacity remuneration mechanisms, the highest idealized gross margins in 2017 are observed in Germany (€ 24.2 million) and Great Britain (€ 24.0 million). Meanwhile, Belgium offers on average the lowest opportunity for profit[69], with a gross margin measured at € 12.3 million (51% lower than the British and German numbers).

129. Interestingly, the low gross margin of the Belgian plant comes despite a reasonable margin on the day-ahead energy market (€ 25.7 million, versus € 24.2 million on average). Belgium appears to suffer from a high level of transmission related costs (€ 12.6 million). In this perfect foresight configuration, this amounts to 49% of its cumulated revenue, which is the highest share observed in the benchmark with Great Britain, with € 22.7 million representing 49% of its cumulated revenue.

[68] The estimated gross margins are the results of an optimization whose margin of error is € 200,000 upwards. For example, if a gross margin of €16.2 million is measured, the actual interval of confidence is [16.2 – 16.4].
[69] In reality, the Austrian area (one of the three network tariff areas in Austria) is subject to a specific tariff named 'system provision charge' that increases the costs incurred by the storage by more than € 7 million. A storage plant located in this particular region would thus earn significantly less than the Belgian plant. However, PHS potential is quasi inexistent in this region. It is more interesting to look at the two other Austrian region (Vorarlberg and Tyrol, in which the potential for PHS plants exists), for which the gross margin reaches € 16.7 million (between Belgium and France).

130. France, Germany and Great Britain appear to benefit from specific measures which greatly boost their profitability.

a. In France and in Great Britain, the capacity remuneration mechanisms provide very significant complements of remuneration. In France, the € 7.1 million revenue from the CRM increases the revenue by 37% and the gross margin by 58%. In Great Britain, the € 20.9 million revenue is equivalent to the revenue on the DA. It increases the total revenue by 81% and the gross margin by 680%: the British plant thus seems particularly dependent on the existence and stability of the CRM, as its gross margin would fall to € 3 million without it (and would even be negative in some regions with the highest transmission tariffs for injection)[70]. On the contrary, the CRM implemented in Belgium does not bring additional revenue for a PHS plant since it has no interest to be part of strategic reserves.

b. The German plant benefits from the total exemption of network tariffs for ten years, as it is assumed that the simulated storage plant was recently refurbished and expanded[71]. Therefore, the quasi entirety of its margin on the DA goes to the gross margin. With rough estimations, one could show that without the exemption the German plant would fall back to levels of gross margin similar to Austria and Belgium.

131. The Austrian case is interesting, as even in the best case situation (the Vorarlberg and Tyrol regions, where system provision charges are equal to zero) the gross margin remains much lower than in France, Germany and Great Britain, despite specific tariffs for PHS. This is due to the high level of remaining charges to be paid even by eligible plants (see appendix 5.1 for more details). Furthermore, the specific tariffs increased from 0.085 to 0.233 cents of €/kWh in 2018, which affects even more the profitability of Austrian PHS.

Box 2. From idealized gross margin to an estimation of actual profitability

The assumptions of the simulation suppose that the storage plant is omniscient and economically rational. Several simplifying assumptions are thus taken that tend to overestimate the revenue compared to reality. In particular, the modeled storage plant benefits from perfect foresight, and is able to anticipate the prices and volumes on the different markets, for the year ahead. Resilience (the impact that the plant's bid has on the market equilibrium if it is not price taker) is assumed null, and the possibility of paradoxically rejected offers[72] on the day-ahead is not studied. The simulation is thus based on the maximization of its gross margin, assuming that the plant is able to adjust perfectly each decision (of injection and withdrawal on the DA) for the whole year ahead, at the same time. Another major optimistic assumption concerns the full availability of the plant for the whole year, whatever the need for maintenance.

These simplifying assumptions imply that the measured gross margin levels are optimistic compared to reality. For example, in reality, the plant does not know prices in advance, or can estimate them with a high level of uncertainty. Its production or consumption decisions can then turn out to be inefficient. According to Electrabel's teams and in particular those running the Coo PHS station, it is

[70] As mentioned in the qualitative benchmark, results for countries with a capacity market should be used with caution. Indeed, the existence of a capacity market may reduce the energy price spikes and then revenues earned from the arbitrage on the energy market. For France, this impact is considered in the quantitative results since the capacity market was already in place for 2017. For Great Britain, the first year concerned by the capacity market is 2018/2019; therefore, revenues from the energy market may be lower only from that date. However, this reduction is difficult to forecast, in particular in an interconnected power system.
[71] As a reminder, one assumes that the plant fulfills the eligibility criteria for exemption in Germany for plants built before 4 August 2011: size of reservoir should be increased by at least 5% or their turbine output should be increased by at least 7.5%.
[72] See the second note for more details on paradoxically rejected offers.

especially impossible to earn 100% of the perfect foresight net revenue on the DA; a more probable outcome would be about 80% at most[73]. A more realistic simulation of PHS behavior, taking into account the absence of perfect foresight, is realized in the second step of the study. It shows a 25% impact of this sole assumption on net DA revenue for a Belgian plant similar to Coo-Trois Ponts. As a first approximation, one could thus expect that the decrease of revenue on the DA translates into a decrease in the gross margins in each country of at least € 4 million lower than what the simulations show. However, refining the simplified assumptions should not change the main conclusions with regard to the relative position of each country. In particular, Belgian PHS would remain far behind its neighbors in this main simulation scope.

It should also be reminded that the estimation of actual profitability levels requires considering all costs and revenues, and not only the limited view of the gross margin when the plants only participate to DA and CRMs. One should take into account:

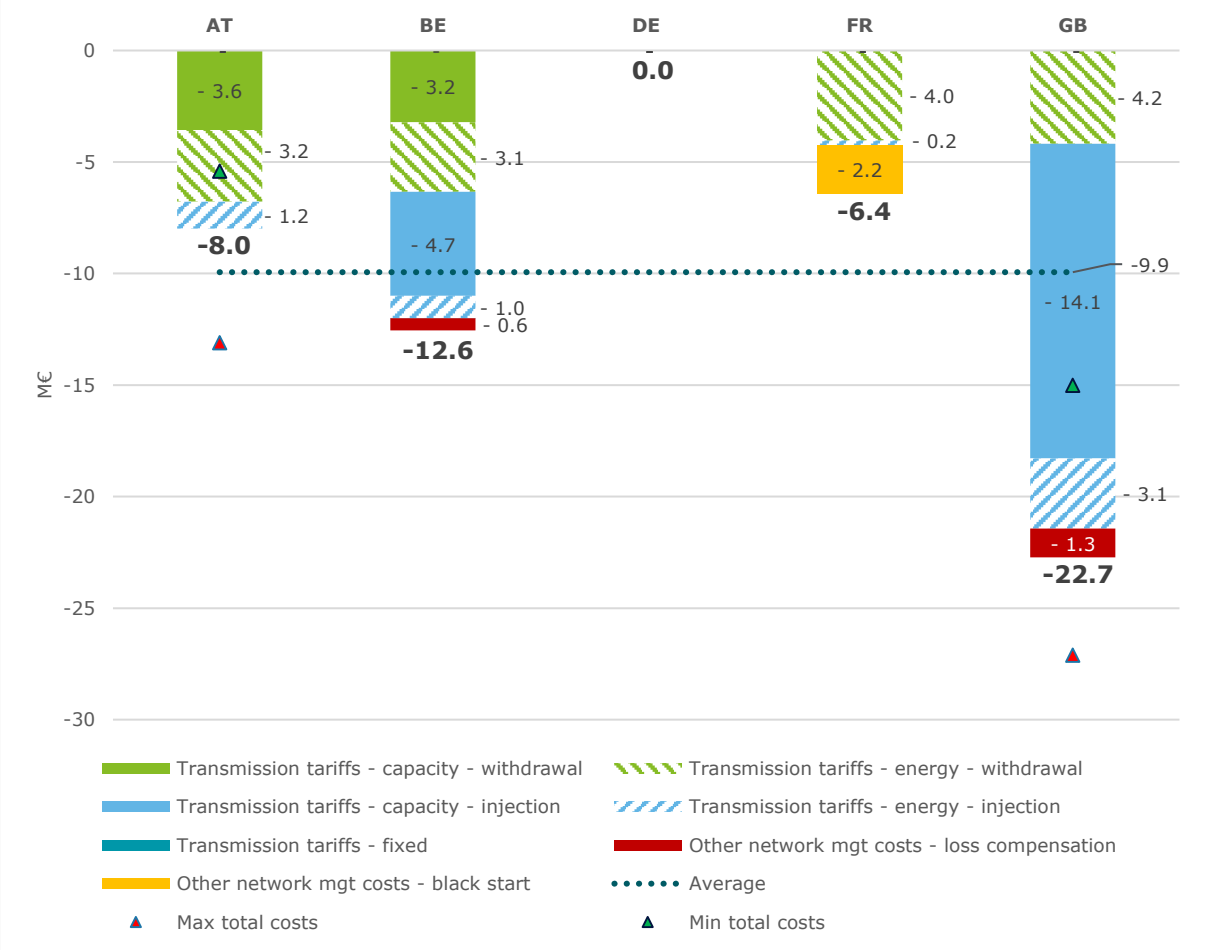
1) The impact of participation of ancillary services on revenue. A first estimation is done on a theoretical basis in appendix 5.8.1 (for frequency reserves), and a more precise assessment approaching reality is realized in the second step of the study for Belgian PHS.

2) The other costs incurred by the plant independently of its behavior on the different markets and mechanisms. These are remaining operational costs (personnel, insurances, market dispatching, …, estimated at € 10 million by Electrabel for the Coo-Trois Ponts PHS plant), and lifetime extension works needed to operate at full capacity (€ 5 million according to Electrabel)[74]. Again, their taking into account should not change the fact that Belgian PHS cannot compete with its neighbors, because they should amount to the same order of magnitude from one country to the other. It should be highlighted that in Belgium and Austria, the gross margins on DA and CRMs are insufficient to cover these costs. The revenue from ancillary services would be critical for these two countries to reach profitability, or at the very least to limit the operating losses (see appendix 5.8.1 and the second note for a more precise assessment taking into account reserves).

[73] The Electrabel team running the Coo PHS plant communicated an estimated ratio of 60% in reality for the plant.
[74] Source: Electrabel internal analysis. The data was not crosschecked by Deloitte. Deloitte cannot be held accountable of any use of these costs and of the resulting estimations

Focus on the results regarding transmission related costs

Figure 4. **Breakdown of transmission related costs incurred by the PHS plant**



Quantitative benchmark – National markets – DA+CRM - 2017

132. As a reminder, transmission related costs include (i) transmission tariffs (including tariffs corresponding to losses, balancing and system services) and (ii) other network management charges, e.g. due to non-remunerated obligations for ancillary service procurement or for loss compensation.

133. Figure 4 above shows an average cost of € 10 million for 2017, with strong differences between countries on both the level and the breakdown of transmission costs. Germany is in the most favorable position thanks to the total exemption of transmission tariffs for main storage facilities. The German plant does not incur any transmission cost, which enables to earn the quasi entirety of its net revenue on the DA. At the opposite, Great Britain has the highest level of transmission costs with € 22.7 million on average. The Belgian plant has the second highest transmission costs among the selected countries with € 12.6 million.

134. As explained in paragraph 131, Austria on average does not benefit as much as expected from the specific tariffs for storage. The specific tariffs increased from 0.085 to 0.233 cents of €/kWh (+274%) in 2018, which represents around € 2 million euros of additional cost for the Austrian plant. On average, the Austrian transmission related costs are thus higher than those of France, even if the costs for plants located in Vorarlberg and Tyrol remain lower.

135. It is worth highlighting that energy-based tariffs and costs drive significantly the anticipated revenues and margins of PHS plants. Variable injection or withdrawal costs indeed modify the perceived buying and selling prices on the day-ahead, and thus distort the spread which is available to the storage plant. As a result, the impact of variable costs (and in particular transmission tariffs) is more than the displayed figure above. It also leads to a loss of opportunity on the day-ahead market, less volumes and thus lower total profits.

136. Among the other notable results, one can identify the following:

a. The capacity tariffs in Belgium and Great Britain have a major impact on the cumulated annual costs and thus on the profitability, with € 7.9 million in Belgium (63% of transmission related costs) and € 14.1 million in Great Britain (62% of transmission related costs). It is largely expected because capacity tariffs tend to penalize (consumption or generation) facilities with a low load factor, like PHS.

b. Austria, Belgium and Great Britain pay tariffs for injection and for withdrawal. This is especially critical for Belgium and Great Britain where storage plants could in theory be liable to both injection and withdrawal capacity charges.

c. The costs of obligations for loss compensation in Belgium and Great Britain remain small compared to the remaining transmission tariffs: they represent € 0.6 million in Belgium (4% of transmission related costs) and € 1.3 million in Great Britain (6%).

d. Finally, the French plant incurs a significant cost due to its obligation to provide non-remunerated black-start, with around € 2 million.

Focus on the results taxes and surcharges

Figure 5. **Breakdown of taxes and surcharges incurred by the PHS plant**

Quantitative benchmark – National markets – DA+CRM – 2017

137. Other taxes and surcharges incurred by PHS plants are significantly lower than transmission related costs. The highest costs are observed in Austria (€ 2.2 million) and in Germany (€ 2.1 million). Belgium and France are close to each other in level, with respectively € 0.8 and 0.6 million euros only.

138. With regard to the breakdown, all taxes and surcharges are related to green certificates or public service obligations, half of which concerning especially renewable energy sources.

Preliminary conclusion

139. Belgian PHS does not benefit from a level playing field with the neighboring countries with regard to their gross margin. The simulation of the modeled plant's behavior in each national market, considering participation to DA and CRMs, highlight the weak prospects in Belgium. The country shows the lowest idealized gross margin with € 12.3 million – twice as less as Germany and Great Britain, and copes in particular with a high level of transmission tariffs (€ 12 million).

140. France, Germany and Great Britain benefit from specific measures which greatly boost their profitability. Revenue from Capacity Remuneration Mechanisms in France and Great Britain happen to compensate their transmission costs, which is especially critical in the British case. The exemption of tariffs in Germany, for which it is assumed that the storage plant is eligible,

amounts to the same effect: the storage plants in those three countries are able to earn the quasi-entirety of their net revenue on the day-ahead.

3.2.2 Comparison of transmission costs and taxes, all other things being equal

141. The evaluation of the impact of transmission costs and taxes on profit can be further refined by standardizing the analytical framework in which the benchmark is run. The selected methodological approach consists in simulating the PHS plant in the context of Belgian market characteristics (Belgian products, prices and volumes for each market), but replacing successively the Belgian regulatory and fiscal framework by each of the other national frameworks.

142. This analysis is done in the same framework than used in section 3.2.1: the plant's operational choices and valuation options only include arbitrage on the DA market and the (eventual) CRM. As the plant is only simulated according to Belgian market characteristics, this of course means that there is no revenue from CRM.

143. The objective of this 'level playing field' benchmark is thus to only test and compare transmission related costs and taxes in a standardized market context that is the Belgian day-ahead market. The methodology is closer to the assumptions of the 2017 CREG study and it enables to measure precisely the impact that each set of tariffs/taxes/obligations would have on the plant's DA arbitrage, for a single day-ahead price curve. Comparing these results to those for national markets in section 3.2.1 also enables to compare the impact of each country's market characteristics (existence of CRM, prices on the DA) on the idealized gross margin.

144. It should be mentioned that compared to the other quantitative results, the Netherlands are here included.

Figure 6. **Comparison of national regulatory and fiscal impact on the idealized gross margin, in the context of the Belgian DA market**

Quantitative benchmark – Belgian market but national frameworks – DA(+CRM) – 2017

145. The results summarized in figure 6 above confirm that Germany is the country with the most favorable regulatory and fiscal framework. Its gross margin reaches € 25 million, which is 37% higher than the second best gross margin for France (€ 18.3 million). On the opposite, Belgium remains among the lowest ranked countries and is equivalent to the Netherlands as regards the impact of tariffs and taxes. It is almost 3-million lower than the average (€ 14.9 million). As expected, the British regulatory framework is the most unfavorable: the magnitude of capacity-based tariffs (€14.1 million) is sufficient to explain the gap with France and Germany, and is not compensated by the capacity mechanism in the simulation. The idealized gross margin with the British framework is thus only € 6.6 million.

146. The Netherlands show a balanced framework compared to Belgium in terms of cumulated costs, but the countries differ in structure. The transmission related costs for the Dutch case amount to € 13.5 million but are almost exclusively explained by capacity-based tariffs on withdrawal. The amount of taxes and surcharges is also reasonable with € 1.5 million, driven by public services obligation for RES subsidies but also an electricity tax amounting to € 1.1 million: this is the only country in the benchmark to have such a tax for PHS.

147. Compared to the results of the main benchmark in section 3.2.1 (simulation in each national market, for DA and CRM only), the results are very stable, especially for Germany and Austria. A first explanation for this stability is due to the similarities between market prices in Belgium, Germany and Austria in 2017. Indeed, this is the only difference between the two set of results for Germany and Austria. France also shows stable results (€ 1 million lower in the present simulation) despite the absence of a capacity remuneration mechanism. This is due to an increase

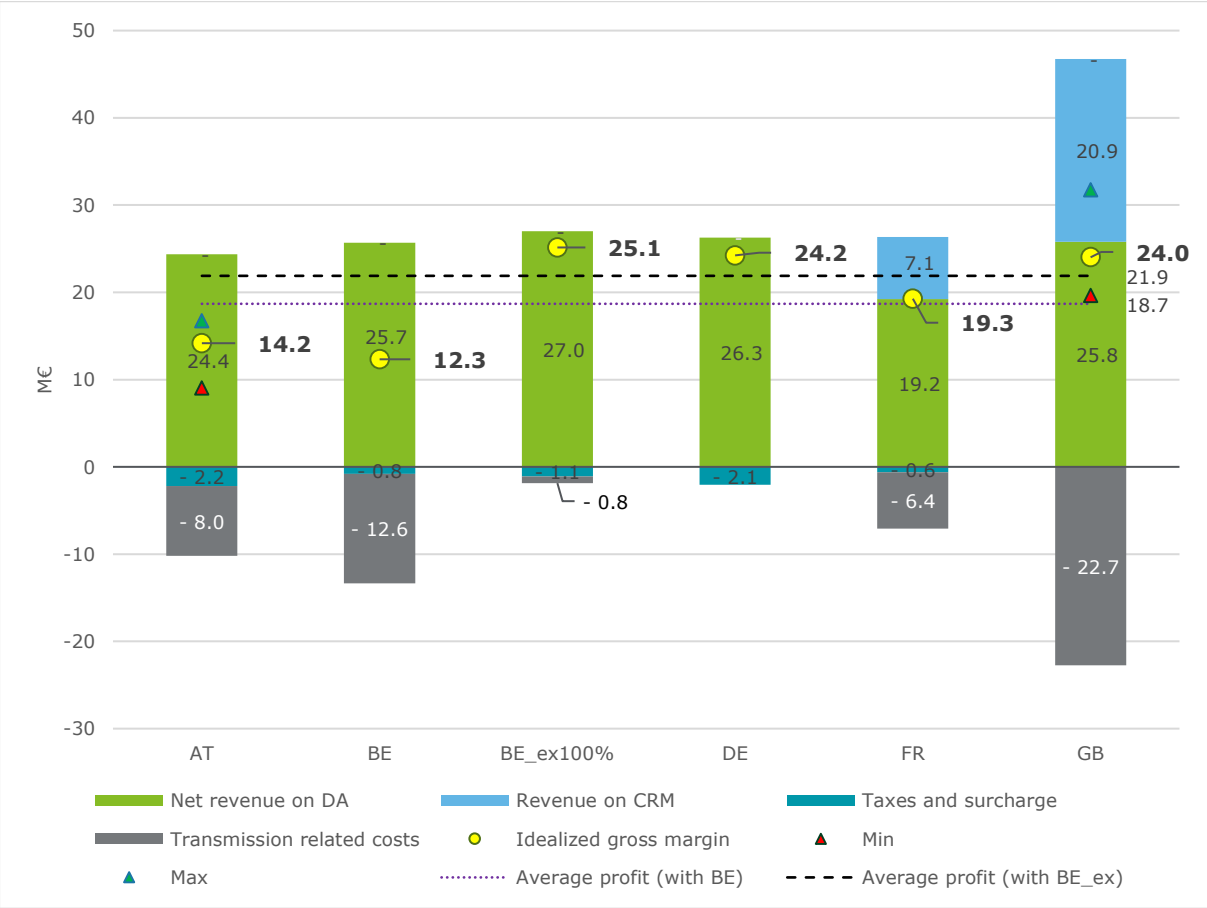
by 35% of the net revenue on the day-ahead: the available spreads on the DA are much more interesting in Belgium than in France. Again, as expected the British case shows the most extreme variation: as the net revenue on the day-ahead was already similar to the one earned in Belgium, the absence of the capacity remuneration mechanism completely affects the gross margin.

3.2.3 Evaluation of a potential tariff exemption in Belgium

148. The previous exercise has shown that regulatory and fiscal rules can have a strong impact on the decisions on the DA and on the eventual profitability, all other things being equal, while box 2 in section 3.2.1 has raised some questions regarding the ability of the gross margin to cover operational and lifetime extension costs.

149. Among the options to ensure the sustainability of existing Belgian storage and to incentivize new investments, an adjustment of network tariffs was identified by the legislator and is now the object of the consultation. To fuel the discussion, the study team has simulated the impact that a total exemption of network tariffs (similar to the German approach) would have on the profitability of Belgian PHS. The assumptions for the simulation were those of a participation of plants in each country to DA and in 2017, in alignment with the methodology used in sections 3.2.1 and 3.2.2. The results of this test are displayed in figures 7 and 8.

Figure 7. Test of the impact of a total tariff exemption for PHS in Belgium



Quantitative benchmark – National markets – DA+CRM – 2017

150. According to the simulations, the total exemption of transmission tariffs in Belgium doubles the idealized gross margin, which increases from € 12.3 to 25.1 million. It enables Belgian PHS

to benefit from a level playing field with German and British storage. Such an increase in profitability would give strong incentives to launch new investments for Belgian PHS and to position it among the most attractive countries for PHS in Western Europe.

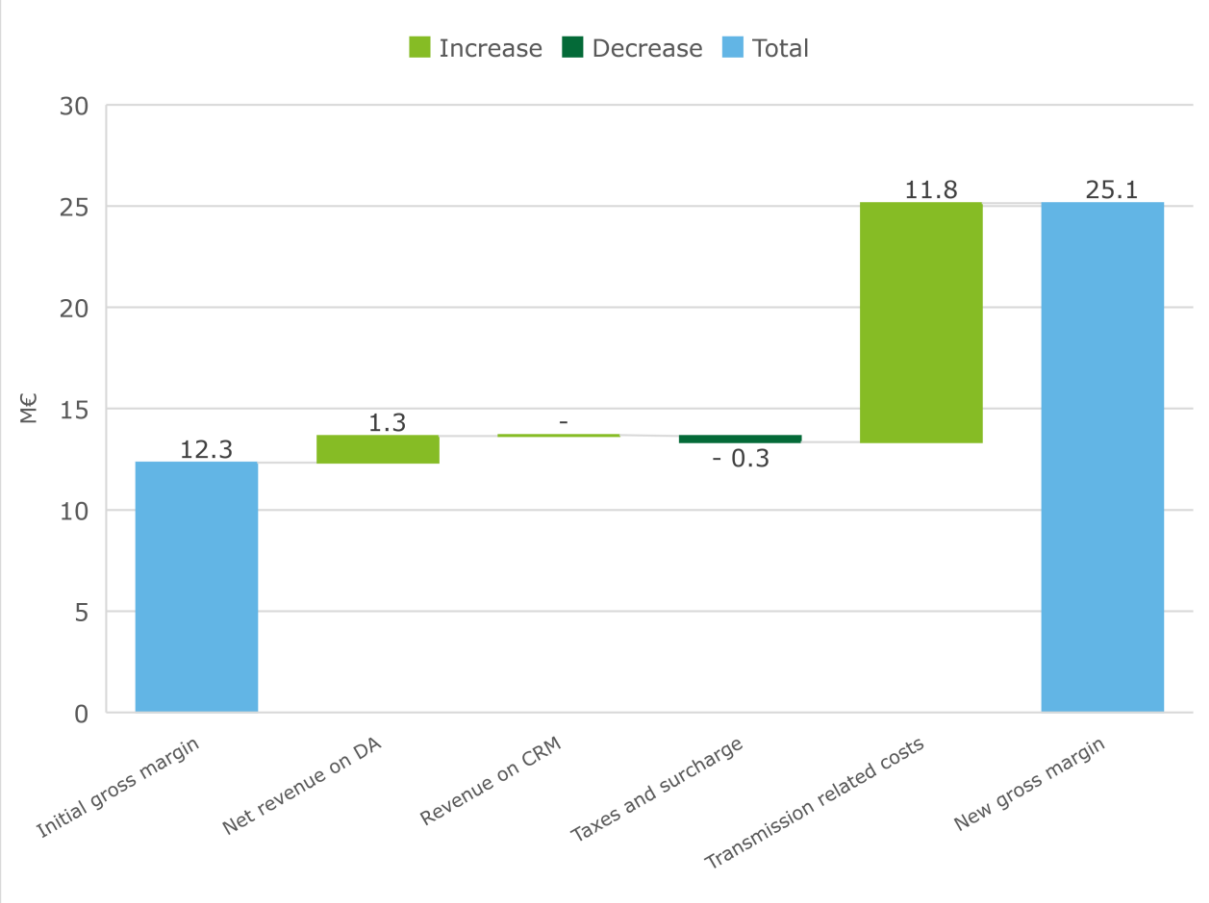
151. Figure 8 hereafter shows the compensating effects which lead to the higher-level profitability. Tariff exemption for PHS thus has the following impact on the plant's costs and revenues:

a. First, the exemption from energy-based variable costs enables the plant to access lower spreads on the day-ahead. This mechanically leads to higher volumes exchanged on the day-ahead: for 2017, the total withdrawals increase from 1.38 to 1.90 TWh (+38%). However, this higher volume does not necessarily mean higher net revenue on the day-ahead: the increase in revenue from additional selling is almost compensated by the increase in costs of buying more on the day-ahead, at a more expensive price. As a result, the total net revenue on DA is quite stable with and without network tariffs: around € 26-27 million.

b. Second, the increase in injections and withdrawals leads to a marginal increase of volume-based taxes and surcharges. The impact is however marginal, at € 0.3 million.

c. Finally yet importantly, the exemption enables the plant to save the entirety of its tariffs. As shown in the figure, this is the main driver for the higher profitability: volume increases along with net revenue on DA, but the totality of this volume is now exempt from tariffs.

Figure 8. **Distributed impact on gross margin of a total tariff exemption in Belgium**



Quantitative benchmark – National markets – DA+CRM– 2017

4 Conclusion

152. The results highlight the variety of PHS profitability drivers and their impact in the studied countries.

a. Regarding transmission related costs, there is a large diversity of transmission tariffs, charges and obligations costs that the PHS plant has to pay. In some countries those costs are fixed or proportional to the installed capacity; they can also be indexed on the maximal injection or withdrawal power, which is *generally* the same. They are particularly significant in Belgium and in Great Britain. In all countries, variable charges are also applied on the total injections (e.g., injection-based tariffs or charges in Austria, Belgium and Great Britain) or withdrawals (Austria, Germany, France and Great Britain with BSUoS). Germany and Austria both present specific regulatory regimes for PHS but it translates differently: German PHS is supposed in the modeling to be eligible for a total 10-year exemption of network tariffs[75], while the specific tariffs in Austria are still significant and are completed by other charges related to network management.

b. Regarding taxes and surcharges, all countries but Great Britain apply some to energy storage. In all countries those charges are particularly related to public service obligations for the power system and renewable subsidies. It is important to mention that fiscal frameworks are often unclear as to the nature of PHS as either an energy consumer or a producer. For example, the British framework does not explicitly state that transmission-connected PHS is considered as a producer, while in practice it seems to be the case, thus allowing a complete exemption of taxes and surcharges for the plant. In all other countries, PHS is generally considered as a consumer but exemption regimes are in place for some taxes in Belgium, Germany and Austria.

c. Finally, the remuneration conditions of PHS are contrasted from one country to another. Firstly, all PHS plants can of course realize arbitrages on the energy markets to benefit from the spread between high and low prices, but this can amount to different outcomes depending on the national spread[76] and on the distortive effect of energy-based costs and tariffs, which affect the economic decisions of the operator. Secondly, only France and Great Britain have capacity remuneration mechanisms (capacity markets) which are suitable for PHS, as strategic reserves in Germany and Belgium would not be interesting for storage plants in operation. The gain in profitability thanks to these markets is very high, even if their existence may theoretically be accompanied by a decrease of available spreads on the energy markets (producers do not have to bid at the highest prices anymore because they cover their fixed costs through capacity market revenue). Finally, the conditions of participation, the volumes at stake and the prices are very divergent for ancillary services. The revenue that PHS can earn on these services is closely linked to the technical constraints but also to the pool of revenue available, which induces major differences in profitability.

[75] All storage built in Germany after 4 August 2011 benefits from a 20-year exemption. However, for the study's purpose one assumes for Germany a PHS plant built before 4 August 2011. Such a plant can also benefit from a 10-year exemption of network tariffs if its technical characteristics have been improved: size of reservoir should be increased by at least 5% or their turbine output should be increased by at least 7.5%. The exemption begins at the date of the expansion's commissioning. It is generally known that a large majority of old PHS in Germany have made these improvements to benefit from the exemption. Therefore, this is what one also assumes for the PHS German plant in the study.
[76] The spreads are national when congestions appear on interconnections. Meanwhile, DA prices in Germany and Austria are always identical.

153. The quantitative results for participation to DA and CRM confirm that France, Germany and Great Britain are the most favorable countries for PHS with a gross margin around or higher than € 20 million. They place Belgium at the bottom of the profitability ladder.

a. France, Germany and Great Britain benefit from specific advantages which enable them to retain the quasi entirety of their net revenue on the day-ahead. In France and Great Britain, revenue from capacity markets (respectively € 7 and 21 million) almost compensate the incurred costs and taxes, which is particularly important in the British case, where the capacity-based tariffs are very unfavorable to storage plants (which present a lower load factor than other producers). German PHS is meanwhile assumed to fulfill the conditions for tariff exemption[77], which helps it realize the best idealized gross margin in this simulation.

b. Austria is in an intermediary position on average, but a closer look shows that the tariffs in regions where PHS is actually located (Vorarlberg and Tyrol) are 6 €/MWh (withdrawn) lower than in the rest of Austria. In these regions, the total cost related to transmission tariffs is € 5 million and the idealized gross margin reaches € 17 million, which isolates even more Belgian PHS as the lowest idealized gross margin earner.

c. Belgium does not benefit from a level playing field with the other countries. Without ancillary services, PHS idealized gross margin is only € 12 million, twice as low as in GB and Germany, and 30% lower than the average for the five countries. This comes despite a net margin on the day-ahead (€ 26 million) close to the average of analyzed countries. The profitability of Belgian PHS is instead impacted by very high transmission tariffs (€ 12 million), second only to Great Britain.

154. A closer look at transmission related costs highlights the strong divergences of regulatory frameworks from one country to another. They confirm the qualitative analysis of those frameworks. The tariff designs are especially critical for Belgian and British PHS, which incur transmission tariffs higher than € 10 million. In both countries, the share of capacity-based tariffs in total incurred costs is significant. It is largely expected because capacity tariffs tend to penalize (consumption or generation) facilities with a low load factor, like PHS. Note that energy-based tariffs (and other costs) also have an indirect significant impact on profitability because they distort the price signals on the energy markets (higher buying or selling prices on the energy market), reducing the number of spreads that the storage plant can monetize.

155. The previously described outputs concern the case where PHS can only participate to the day-ahead energy market and CRMs. As explained in the methodology, they give an optimistic[78] yet reasonable[79] insight on the behaviors and profitability of PHS when plants cannot participate to ancillary services. In the sensitivity analysis, it was however possible to realize a preliminary theoretical assessment of PHS' participation to frequency reserves. This analysis was based on the most extreme assumptions which would maximize the provision and the monetization of frequency services, such as full technical possibility to do hydraulic bypass or the assumption that the plant can earn 100% of the market without influencing its price (price-taker with no resilience). The extreme nature of these assumptions makes them unrealistic and represent the (unreachable) upper boundary when all realistic constraints are relaxed. They should not be regarded with the same level of certainty and realism than the benchmark's main set of results, but they provide some very striking findings for each country. In particular, they show that even extremely optimistic assumptions as to the participation to frequency services do not enable

[77] Conditions for PHS build before 4 August 2011 (see footnote 6)
[78] Some assumptions had to be taken to tackle modeling limitations, leading to overestimation of profitability.
[79] The orders of magnitude of profitability gaps between countries should reflect reality. As already explained, it should be reminded that those results only illustrate the relative levels of profitability from one country to another for a theoretical plant; absolute estimations of actual PHS profitability in a given country, for a given plant, should not be extracted from these values.

Belgian PHS to compensate for its lag in profitability, especially with regard to France, Germany and Great Britain.

156. It should be noted that in reality profitability is more relevant to the investor than gross margins, both for comparison with other countries as well as for decisions regarding new investments or closure. Profitability is extracted from gross margins by subtracting all other costs such as remaining operational cost (personnel, market dispatch, insurances…) or costs related to lifetime extension works, which can amount to respectively € 10 and 5 million for a PHS plant similar to the one that is modeled in the study[80]. This does not change the benchmark's main conclusions as to the place of Belgian PHS compared to Austria, France, Germany and Great Britain because these additional costs are assumed to be equal in each country for the modeled plants. Furthermore, the simulations in the study take place in an idealized setting where the plant is omniscient to all future prices and volumes, is independent from any portfolio, is economically rational and is not exposed to a risk of resilience on the markets (assumption of price-taker). These simplifying assumptions were vital in order to realize a level modeling of PHS in all countries and to compare them, but they prevent from looking at the actual operating and economic conditions of PHS. It is expected that any sophistication would however lead to the same conclusions: indeed, the relaxing of major hypotheses such as perfect foresight should affect all compared plants with a similar order of magnitude.

157. In conclusion, the benchmark's results confirm that there is no level playing field between the studied countries. In particular, Belgian PHS appears to lag millions behind France, Germany and Great Britain, pulled down by relatively high transmission tariffs and not compensated by any revenue from capacity mechanisms. The results raise a second question regarding the financial viability of Belgian PHS: scientific intuition suggests that a more realistic simulation would have resulted in operating losses. This question is the subject of the second step of the study[81], which looks at the actual economic conditions of the Coo-Trois Ponts PHS plant, and which confirms that the operating results of the plant are already durably negative, once all revenues and costs are taken into account. All of this does not bode well for the capacity of Belgian PHS to attract new investments, and can even be cause for concern regarding the sustainability of PHS in the future. With regard to the current consultation on the tariff methodology, the simulation of a tariff exemption in Belgium confirms the intuition that it should tackle the concerns on PHS profitability and help reach a level playing field with France, Germany and Great Britain.

[80] Source: Electrabel internal analysis. The data was not crosschecked by Deloitte. Deloitte cannot be held accountable of any use of these costs and of the resulting estimations.
[81] The second step of the study is described in a second document: *Additional note on the realistic assessment of profitability for the Coo-Trois Ponts PHS plant*, 2018, Deloitte

5 Appendices

5.1 Country specific details: Austria

5.1.1 Transmission network charges in Austria

158. For the Extra-High Voltage (EHV – 380 and 220 kV) in Austria, the country is divided into three tariff areas (Austrian, Tyrol and Vorarlberg), with two TSOs: APG and Vorarlberg.

159. Transmission network charges are set trough the Electricity System Charges Ordinance by the Austrian Regulator E-Control[82]. They are usually updated every year.

160. The Electricity System Charges Ordinance introduces four main tariffs component for users directly connected to the transmission network :

a. The Network usage charges

b. The net Losses charges

c. The System provision Charge

d. The System Service Charge

The Network Usage Charges

161. The regulation introduces a specific regime for this transmission network charges component for PHS. This specific tariff is to be applied in every area, for every voltage level of the transmission network. Table 10 summarizes the value of these charges that have been used in the study.

Table 10. Network Usage Charges for PHS in Austria (specific tariffs)

Energy Component (€/MWh)	Capacity Component (€/MW)
Withdrawal	*Withdrawal*
2.33	1,000

Other Transmission network charges

162. The Net Losses Charge component is a tariff based on both the energy consumed from and the energy injected to the transmission network. It is summarized in Table 11.

[82] https://www.e-control.at/en/recht/bundesrecht/strom/verordnungen

Table 11. Net Losses Charge in Austria

Energy Component (€/MWh)	Energy Component (€/MWh)
Injection	*Withdrawal*
0.36	0.36

163. The system provision charge is a tariff based on the withdrawn capacity. It is determined by network level. However, for the EHV, this charge have only to be paid by the PHS located in the Austrian Area (where, in reality, no PHS are in activity). Therefore, the study presents, for the capacity component, an average of the charges incurred by the PHS at national level[83]. For Austrian area, the system provision charge is equal to 7,700 euros per MW.

164. The system service charge is an energy component that has to be paid for the injection of electricity into the transmission network, by power plants and other generators with a power capacity of at least 5 MW. Therefore, regarding the maximum production capacity of the PHS, this energy component is considered in this study. It is equal to 0.980 €/MWh injected, for each area (i.e. Austrian, Tyrol and Vorarlberg).

5.1.2 Taxes and surcharges in Austria

165. Three main categories of taxes and surcharges are applied in Austria for electricity consumers[84]:

a. The Electricity levy

b. The Community levy

c. Public Service Obligation for Renewable Electricity Subsidies (PSO for RES)

166. Nonetheless, a specific regime for PHS is applied. Indeed, PHS is exempted from the electricity levy, as the electricity that is "consumed in order to be used to generate electricity" is exempted from the tax.

167. The Community levy has been excluded from the perimeter of the benchmark, because it is a surcharge for the use of the public land and is thus not related to electricity consumption/generation.

168. The PSO for RES in Austria is divided into two main taxes:

a. The Renewable contribution, which is set as a uniform percentage applied to the transmission network charges. The percentage for the year 2018 is 24%.

b. The flat-rate renewables charge per metering point, which is a fixed charge paid for each metering point, in euros per year. Its amount varies depending on the voltage level at which the plant is connected. For the EHV, the PHS in the study pays 100 euros per year.

[83] As the PHS have to paid a capacity component for network usage charges, we calculated the average for the global capacity component as follow: (1000 + 1000 + 1000 + 7700)/3
[84] https://www.e-control.at/en/marktteilnehmer/strom/strommarkt/preise/steuern-und-abgaben

5.1.3 Capacity remuneration mechanism

169. There is no CRM implemented in 2018 in Austria.

5.1.4 Frequency control reserves

FCR

170. FCR products are procured by the Austrian TSO thanks to the common European market. The demand of the Austrian TSO for FCR is equal to 62 MW in 2017[85]. Moreover, Austrian FCR providers can offer their services abroad up to 100 MW[86]. The average price on this market is equal to 14.6 €/MW.h in 2017.

aFRR

171. aFRR products are procured through a national tender. Upward and downward products are procured separately. Moreover, in 2017, the Austrian TSO defined the products on a weekly basis with a distinction between peak and off hours[87]. The peak product is defined for weekdays from 8am to 8pm (i.e. for 60 hours). Off peak product corresponds to the remaining hours (00am to 8am and 8pm to 00am for weekdays and all hours for weekends, i.e. for 108 hours).

172. The average prices and volumes for 2017 for each type of products are shown in Table 12.

Table 12. Average volume and prices for aFRR in Austria in 2017[88]

	Upward	Downward
Peak hours	200 MW ; 3.48 €/MW.h	200 MW ; 1.79 €/MW.h
Off-peak hours	200 MW ; 0.94 €/MW.h	200 MW ; 4.62 €/MW.h

mFRR

173. mFRR products are procured through a national tender, with a distinction between upward and downward products. Moreover, the Austrian TSO procures these products with two different types of procurement markets. The first one is the weekly auctions. Products are traded for several days of the same weeks. More precisely, they are defined on a 4-hour time slots (00am-4am, 4am-8am, 8am-12pm, 12pm-4pm, 4pm-8pm and 8pm-00am) with a distinction between weekdays and weekends[89]. Corresponding products as well as average volumes and prices for 2017 are depicted on Table 13 and Table 14.

[85] https://www.regelleistung.net/ext/
[86] https://consultations.entsoe.eu/markets/fcr-cooperation-potential-market-design-evolutions/supporting_documents/20170102%20FCR%20market%20consultation.pdf
[87] https://www.apg.at/en/market/balancing/secondary-control/tenders
[88] https://transparency.entsoe.eu/
[89] https://www.apg.at/en/market/balancing/tertiary-control/tenders

Table 13. Average volumes and prices for weekly upward mFRR in Austria in 2017[90]

	Monday	Tuesday	Wed.	Thursday	Friday	Sat.	Sunday
00am-4am	203 MW ; 0.48 €/MW.h					203 MW ; 0.33 €/MW.h	
4am-8am	203 MW ; 1.57 €/MW.h					203 MW ; 0.49 €/MW.h	
8am-12pm	203 MW ; 3.99 €/MW.h					203 MW ; 0.96 €/MW.h	
12pm-4pm	203 MW ; 2.45 €/MW.h					203 MW ; 0.88 €/MW.h	
4pm-8pm	203 MW ; 4.68 €/MW.h					203 MW ; 1.17 €/MW.h	
8pm-00am	203 MW ; 1.42 €/MW.h					203 MW ; 0.56 €/MW.h	

Table 14. Average volumes and prices for weekly downward mFRR in Austria in 2017[91]

	Monday	Tuesday	Wed.	Thursday	Friday	Sat.	Sunday
00am-4am	127 MW ; 4.68 €/MW.h					127 MW ; 7.08 €/MW.h	
4am-8am	127 MW ; 3.14 €/MW.h					127 MW ; 7.51 €/MW.h	
8am-12pm	127 MW ; 0.67 €/MW.h					127 MW ; 4.45 €/MW.h	
12pm-4pm	127 MW ; 0.90 €/MW.h					127 MW ; 6.87 €/MW.h	
4pm-8pm	127 MW ; 0.54 €/MW.h					127 MW ; 3.26 €/MW.h	
8pm-00am	127 MW ; 1.70 €/MW.h					127 MW ; 3.78 €/MW.h	

174. The second type of auction is a daily auction[92]. Products are defined as previously on a 4-hour time slots for each day. Average volumes and prices for 2017 are depicted on Table 15.

Table 15. Average volumes and prices for daily mFRR in Austria in 2017[93]

	Upward	Downward
00am-4am	80 MW ; 0.68 €/MW.h	45 MW ; 5.00 €/MW.h
4am-8am	80 MW ; 1.46 €/MW.h	45 MW ; 4.10 €/MW.h
8am-12pm	80 MW ; 4.05 €/MW.h	45 MW ; 1.69 €/MW.h
12pm-4pm	80 MW ; 2.88 €/MW.h	45 MW ; 2.64 €/MW.h

[90] https://transparency.entsoe.eu/
[91] Ibid.
[92] There was no daily auctions until 01/14/2017.
[93] https://transparency.entsoe.eu/

	Upward	Downward
4pm-8pm	80 MW ; 4.54 €/MW.h	45 MW ; 1.46 €/MW.h
8pm-00am	80 MW ; 1.33 €/MW.h	45 MW ; 2.03 €/MW.h

175. Thus, on overall, there are 54 different products upward for one week (and the same number downwards).

5.1.5 Voltage support

176. To the best of our knowledge, voltage control in Austria is not documented in the available documents published by the Austrian TSO. However, according to the survey of ENTSO-E[94], this provision is a mandatory service and is remunerated.

5.1.6 Black start

177. To the best of our knowledge, provision of black start services in Austria is not documented in the available documents published by the TSO. However, according to the survey of ENTSO-E[95], TSOs procure this service through specific contracts which is remunerated.

[94] https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS_Survey_final_10.03.2017.pdf
[95] Ibid.

5.2 Country specific details: Belgium

5.2.1 Transmission network charges in Belgium

178. The Belgian transmission network charges are divided into six main categories:

a. The capacity charge for the monthly peak demand, which is a charge paid on the peak demand capacity for the operation month. The peak is calculated based on the eleventh monthly peak demand, between 9-11am and 5-9pm, from November to March. As one of the main characteristics of a PHS is to withdrawn electricity during off-peak period (when prices are low) and to reinject it during peak period (when prices are high), the study assumes that the modeled PHS is never consuming during these peak-periods, and thus does not pay the monthly peak demand charge.

b. The capacity charge for the annual peak demand, which is a charge paid on the peak demand capacity for the operation year. As the methodology for its calculus is the same than the methodology for the monthly peak demand charge, the study also assumes that the modeled PHS does not pay it.

c. The capacity charge for the maximum capacity put at disposal, which is a charge in €/MW put at disposal to the transmission grid (i.e. injected). It is calculated on the maximum power capacity of the PHS.

d. The energy charge for system management, which is an energy component tariff paid for each MWh withdrawn from the transmission network (€/MWh).

e. The energy charge for black-start, which is an energy component tariff (in €/MWh) paid both by producers and by consumers for the electricity injected to and withdrawn from the Belgian transmission network.

f. The energy charge for market integration, which is an energy component tariff (in €/MWh) paid for each MWh withdrawn from the transmission network.

g. Table 16 summarizes the value of each charge use in this report.

Table 16. Summary of Belgian transmission network charges

	Withdrawal	Injection	Units
Monthly capacity peak	0	-	€/MW
Annual capacity peak	0	-	€/MW
Capacity put at disposal	-	4,659.8	€/MW
System management charge	0.4978	-	€/MWh
Black-Start charge	1.371	0.9644	€/MWh
Market integration	0.387	-	€/MWh

179. Finally, Belgium also applies a fixed charge for the metering. It is a fixed tariff of 502.12 € per year per metering point.

180. With regard to electricity losses on the transmission network, Elia provides each year on its website the percentage of active losses on the transmission network that have to be compensated by the Balancing Responsible Party which consumes electricity. Table 17 highlights these percentages. To evaluate the charges incurred to the storage facility by the compensation of transmission losses, the study applied these percentages of active losses to each withdrawn MWh from the transmission network by the modeled PHS.

Table 17. Transmission losses rates to be applied in Belgium, 2017

Year	Peak hours96	Long-Off peak hours97
2017	1.35%	1.25%

5.2.2 Taxes and surcharges in Belgium

181. Several taxes and surcharges are applied in Belgium[98] to the consumption of electricity, for consumers directly connected to the EHV (i.e. 380 kV):

a. Public Service Obligation for Offshore Renewable Subsidies which is a surcharge applied on each MWh withdrawn.

b. Public Service Obligation for the funding of green certificates. PHS in Belgium is exempted from this surcharge.

c. The federal Green certificate. In Belgium, PHS are exempted to pay this surcharge.

d. Public Service Obligation for the funding of the strategic reserve, which is a surcharge applied on each MWh withdrawn.

e. The Federal Levy. Since the publication of the last version of the energy law[99], PHS is exempted from the Federal Levy in Belgium. Therefore, it is assumed in the study that the modeled PHS does not paid it.

f. Table 18 summarizes theses taxes and surcharges in Belgium.

[96] Week days, from 8am to 8pm.
[97] Every day, from 8pm to 8am + week-end and off-days
[98] As there is no potential for PHS in Flanders, the only taxes and surcharges studied are those applied in Wallonia.
[99] "*13 Juillet 2017. — Loi modifiant la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité en vue d'améliorer la flexibilité de la demande et le stockage d'électricité*". See the document available here: http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&table_name=loi&cn=2017071306

Table 18. Taxes and surcharges for PHS in Belgium

PSO for RES (offshore wind farm)	0.1518	€/MWh withdrawn
PSO for Green certificate funding	Exempted	
PSO for strategic reserve	0.4298	€/MWh withdrawn
Federal Levy	Exempted	
Green certificate	Exempted	

5.2.3 Capacity remuneration mechanism

182. A strategic reserve mechanism is implemented in Belgium. The TSO procures some capacity, the so-called strategic reserve, to be able to produce during peak hours. However, this capacity cannot produce on the energy market anymore during the remaining hours (and when it produces during peak hours, their associated remuneration is capped). Consequently, it does not seem economically rational for a PHS plant to become strategic reserve, as it will forego any revenues on the day-ahead and on the ancillary services mechanism. Strategic reserves are mainly old power plants which would have been decommissioned from the energy market otherwise.

5.2.4 Frequency control reserves

FCR

183. FCR products are partly procured by the Belgian TSOs thanks to the common European market. The demand of the Belgian TSO for FCR on this market is on average equal to 30 MW[100]. Moreover, Belgian FCR providers can offer their services abroad up to 100 MW[101]. Besides, the Belgian TSO procures three other FCR products: two asymmetric products (up and down) and one symmetric product whose technical characteristics are more stringent than the product procured on the common market (the Belgian FCR product has to be activated between -100mHz and +100mHz while the product contracted on the European market has to be activated between -200mHz and +200mHz)[102].

184. According to operational return on experience from Electrabel, asymmetric FCR products are not considered in this study since they are not provided by PHS plants. Only Belgian symmetric FCR and the "European" symmetric FCR are modeled. The average price for the FCR on the common European procurement market is equal to 14.6 €/MW.h in 2017[103]. For the Belgian 100mHz FCR, the average demand of the TSO is equal to 18 MW and the associated price is 33.1€/MW.h on average for 2017[104].

[100] Cf. http://www.elia.be/fr/fournisseurs-et-contractants/categories-d-achat/energy-purchases/Ancillary-services/Ancillary-Services-Volumes-Prices
[101] Cf. https://consultations.entsoe.eu/markets/fcr-cooperation-potential-market-design-evolutions/supporting_documents/20170102%20FCR%20market%20consultation.pdf
[102] Cf. http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-services/Product-Description
[103] Cf. results published on https://www.regelleistung.net/ext/
[104] Cf. http://www.elia.be/fr/fournisseurs-et-contractants/categories-d-achat/energy-purchases/Ancillary-services/Ancillary-Services-Volumes-Prices

aFRR

185. The Belgian TSO procures the needed aFRR volumes through weekly auctions. Trades are asymmetric and encompass the whole week. Associated volumes and prices are the same upwards and downwards and are equal to 144 MW and 13.8 €/MW.h[105].

mFRR

186. The Belgian TSO procures two types of mFRR in 2017: the R3 standard product and the R3 flex. The difference between both products lies in the constraints on activations that the TSO can require. With a standard product, the plant cannot be activated more than 8 hours a day whereas it cannot be activated more than 2 hours a day with a flex product[106]. Moreover, both products are asymmetric and are procured thanks to monthly auctions. Associated volumes and prices for 2017 are described in Table 19.

Table 19. Average volumes and prices for mFRR in Belgium in 2017[107]

	Standard Product	Flex Product
Monthly	305 MW ; 4.3 €/MW.h	315 MW ; 3.4 €/MW.h

5.2.5 Voltage support

187. Power plants whose maximum output is greater than 25 MW have to contribute to the voltage support. The Belgian TSO also tenders some plants to provide voltage support. These services are remunerated at a non-regulated price[108].

5.2.6 Black start

188. Black start services are procured by the TSO thanks to bilateral contracts (it is not a mandatory service). These services are then remunerated[109].

[105] Ibid.
[106] Cf. http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-services
[107] Cf. http://www.elia.be/fr/fournisseurs-et-contractants/categories-d-achat/energy-purchases/Ancillary-services/Ancillary-Services-Volumes-Prices
[108] Cf. http://www.elia.be/fr/produits-et-services/~/media/files/Elia/Products-and-services/ProductSheets/S-Ondersteuning-net/S6_F_TENSION.pdf
[109] Cf. http://www.elia.be/fr/produits-et-services/services-auxiliaires/~/media/files/Elia/Products-and-services/ProductSheets/S-Ondersteuning-net/S7_F_BLACK_START.pdf

5.3 Country specific details: France

5.3.1 Transmission network charges in France

189. The transmission network charges for the EHV (i.e. HTB3), called TURPE 5, are fixed by the national regulator, the CRE, and applied by the TSO, RTE. For the EHV, they are composed of four main components:

a. An energy component for the electricity injected into the transmission network

b. An energy component for the electricity withdrawn from the transmission network

c. A fixed component for network management (i.e. billing etc.)

d. A fixed component for metering

190. For the EHV, the TURPE 5 does not have time differentiation and capacity related charges.

191. Table 20 summarizes the value of the component described above.

Table 20. Transmission network charges in France – TURPE 5 – HTB3

Energy component for injection	**0.2**	**€/MWh injected**
Energy component for withdrawal	3.1	€/MWh withdrawn
Fixed component for management	8,508.05	€/year
Fixed component for metering	528.12	€/year

5.3.2 Taxes and surcharges in France

192. In France, two main surcharges are applied on the consumption of electricity:

a. The "Composante Tarifaire d'Acheminement" (CTA), which is a surcharge for the funding of the pensions of government officers. It thus does not enter in the scope of the study.

b. The "Contribution Sociale Pour l'Electricité" (CSPE), which is a surcharge applied on each MWh withdrawn from the transmission grid. The CSPE is a Public Service Obligation for Renewable Energy Subsidies (for cogeneration and offshore wind farm particularly). The CSPE is capped at 927 783 €/year since 1 January 2015[110]. Under this amount, the value of the CSPE is 18.3 €/MWh. The study assumes that the PHS consumes enough electricity to reach the cap of 927k € (which is actually the case).

5.3.3 Capacity remuneration mechanism

193. France has implemented a capacity market. With this solution, a new market for capacity is created. On this market, a demand for capacity is defined by the energy suppliers. Indeed, these suppliers must have enough capacity certificates to cover the peak consumption of their clients (otherwise, they will be subject to financial penalties). Regarding the supply, capacity providers

[110] http://www.cre.fr/operateurs/service-public-de-l-electricite-cspe/mecanisme

(for example, generation plants, storage facilities, demand-response…) bid on this market. These providers choose themselves both the volume they submit and the price (contrary to the British capacity market in which they cannot choose the volume). However, the volume they offer should be determined with caution since market players would face penalty if they cannot ensure this volume to be available during peak hours. Moreover, during peak periods, capacity providers must be able to produce during ten hours at the volume they have sold. This constraint reduces the volume that PHS plants with a low size of reservoir (as the one modeled in this study) can provide.

194. To determine the capacity the modeled plant can provide (without high risks of penalties), certified capacities of PHS plants with a similar size of reservoir as the modeled plant (4-5 hours of production at the maximum output) are considered. On average, the certified capacity is about 73% of the maximum output[111]. This derating factor is then considered for the modeled plant.

195. Regarding the capacity price, auctions organized by EPEX Spot determined an average price of 9,342 €/certified MW for 2018[112].

5.3.4 Frequency control reserves

FCR

196. From 01/16/17, FCR products are procured by the French TSO thanks to the common European market. The demand of the French TSO for FCR is equal to 561 MW in 2017[113]. Moreover, French FCR providers can offer their services abroad up to 168 MW[114]. The average price on this market is equal to 14.6 €/MW.h in 2017[115].

197. Before 01/16/17, FCR products were procured through an obligation for largest power plants[116] as it is still the case for aFRR. To simplify, in the simulations, it is considered that the French TSO procured FCR using the common market procurement during these two weeks of January.

aFRR

198. In 2017, the French TSO procures the needed aFRR products based on an obligation[117]. All power plants connected to the transmission network and whose maximum output is larger than 120 MW have to be able to provide some symmetric aFRR. The exact amount they have to provide is compute for each half-hour by the French TSO by splitting its need of aFRR between each plant with this obligation proportionally to its expected production. For instance, if a plant does not expect to produce, its obligation to provide aFRR is zero. If its expected production is 1/60 of the total production, its obligation is roughly equal to 1/60 of the French TSO's need.

199. To determine the required volume for the modeled plant, the historical production of plants that must provide aFRR (notably, nuclear, coal and gas units) is computed in 2017. Given that the modeled plant cannot produce more than 1,000 MW, it is possible to compute an average

[111] Cf. https://clients.rte-france.com/lang/fr/visiteurs/vie/meca_capa/meca_capa_rcc.jsp
[112] Cf. http://www.epexspot.com/fr/donnees_de_marche/capacitymarket
[113] Cf. https://consultations.entsoe.eu/markets/fcr-cooperation-potential-market-design-evolutions/supporting_documents/20170102%20FCR%20market%20consultation.pdf
[114] Ibid.
[115] Cf. results published on https://www.regelleistung.net/ext/
[116] Cf. http://clients.rte-france.com/htm/fr/offre/telecharge/20170101_Regles_services_systeme_frequence.pdf
[117] Ibid. (p 43)

ratio of the aFRR it has to provide based on the demand of the French TSO, which varies from 500 MW to 1150 MW in 2017[118]. On average, this volume is equal to about 13 MW.

200. The associated remuneration is regulated at around 18€/MW.h[119].

mFRR

201. The French TSO wants to procure 1,000 MW upward that can be activated during 4 hours a day[120]. To procure them, products are defined on a weekly basis with a distinction between weekdays and weekends. Consequently, products have to be provided during 2 or 5 days. Moreover, plants not only submit a bid with a volume of reserves they commit to provide (i.e. in MW) but also the number of hours during which they commit to be able to be activated for one day. For mFRR, this duration is equal to 1, 2, 3 or 4 hours. The TSO will then select the cheapest bid to meet its need. For instance, instead of procuring one expensive bid of 1,000 MW which can be activated during 4 hours a day, the French TSO can procure 2 bids of 1,000 MW each and which can be activated during 2 hours only a day. Remuneration of each bid is adjusted according to the maximum duration of activations the plant submits (a 100-MW bid with a 4-hour constraint for activation will earn more than a bid for the same power but which can be activated only 2 hours a day). In the following table, associated characteristics of the mFRR auction are defined for a commitment to be able to be activated during 4 hours a day and 2 hours a day (the latter product is the one considered in the modeling). Moreover, as the remuneration of these products follows a pay-as-cleared rule (contrary to other products), the marginal price is considered in this table and in the study.

Table 21. Average volumes and marginal prices for mFRR in France in 2017[121]

	4 hours of activation a day	**2 hours of activation a day**
Weekdays	1,000 MW ; 2.88€/MW.h	2,000 MW ; 1.57 €/MW.h
Weekends	1,000 MW ; 2.46 €/MW.h	2,000 MW ; 1.35 €/MW.h

RR

202. The RR product shows similar characteristics with the mFRR product. In particular, plants can submit the number of hours during which they commit to be able to be activated for one day. For RR, this duration is equal to 1, 2 or 3 hours. In the following table, associated characteristics of the mFRR auction are defined for a commitment to be able to be activated during 3 hours a day and 2 hours a day (the latter product is the one considered in the modeling). Moreover, as the remuneration of these products follows a pay-as-cleared rule (contrary to other products), the marginal price is considered in Table 22 and in the study.

[118] Cf. https://transparency.entsoe.eu/
[119] Cf. http://clients.rte-france.com/htm/fr/offre/telecharge/20170101_Regles_services_systeme_frequence.pdf (p 62)
[120] https://clients.rte-france.com/htm/fr/offre/telecharge/RRRC2018_Reglement_de_consultation.pdf
[121] https://clients.rte-france.com/htm/fr/offre/telecharge/RRRC2017_Prix_marginaux.pdf

Table 22. Average volumes and marginal prices for RR in France in 2017[122]

	3 hours of activation a day	2 hours of activation a day
Weekdays	500 MW ; 1.96€/MW.h	750 MW ; 1.31 €/MW.h
Weekends	500 MW ; 1.66 €/MW.h	750 MW ; 1.11 €/MW.h

5.3.5 Voltage support

203. Power plants connected to the transmission network must be able to contribute to the voltage support, whose technical characteristics are defined in the connection agreement[123]. This obligation is remunerated at a regulated price[124].

5.3.6 Black start

204. Provision of black start services are compulsory in France for largest plants[125]. In particular, according to the survey of ENTSO-E[126], this obligation applies to hydro units. Moreover, this service is non-remunerated.

[122] https://clients.rte-france.com/htm/fr/offre/telecharge/RRRC2017_Prix_marginaux.pdf
[123] Cf. http://clients.rte-france.com/htm/fr/mediatheque/telecharge/reftech/20170401_article_8-10__v4.pdf (p 5)
[124] Ibid (p 25).
[125] Cf. https://clients.rte-france.com/htm/fr/mediatheque/telecharge/reftech/15-07-06_article_4-5__v2.pdf
[126] Cf. https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS_Survey_final_10.03.2017.pdf

5.4 Country specific details: Germany

5.4.1 Transmission network charges in Germany

205. Since 2011, German PHS plants are, under certain circumstances, totally exempted from transmission network charges. More particularly, the German regulation, through the Energy Economy Act[127], established a specific rule for storage facilities directly connected to the transmission network. A tariff exemption applies to facilities built after 4 August 2011 and expires 20 years after their initial start-up. Pumped-storage hydropower plants built before 4 August 2011 can only be exempted for 10 years[128] provided that their technical characteristics have been improved after the before-mentioned date (the size of their reservoir should be increased by at least 5% or their turbine output should be increased by at least 7.5%).

206. Considering that the operator of the PHS in the study follows a rational behavior, it is assumed that the operator have already made the investment in order to be eligible to the exemption. Therefore, the transmission network charges for Germany are assumed null in the study.

5.4.2 Taxes and surcharges in Germany

207. Several taxes and surcharges are applied in Germany for electricity consumers. Besides, the German legal framework is unclear, as several reductions and exemptions are applied for large consumer as well as for PHS plants.

208. First, PHS are exempted from the EEG levy, which is a Public Service Obligation for Renewable Energy Subsidies[129]. PHS are also exempted from the CHP levy, which is also a PSO for RES, for the funding of cogeneration. Finally, PHS are exempted from the electricity levy.

209. Therefore, the modeled PHS plant is assumed to pay in the study:

a. The Stromnev levy, a surcharge in €/MWh withdrawn, designed to compensate the reductions and exemptions granted to large industrials as well as PHS plants

b. The Levy for Interruptible Load, a surcharge in €/MWh withdrawn

c. The Offshore liability levy, a PSO for RES in €/MWh withdrawn

210. Table 23 summarizes the value of taxes and surcharges applied in Germany.

Table 23. Taxes and Surcharges for PHS in Germany

EEG	CHP Levy	Electricity Tax	Stromnev Levy	Levy for interruptible load	Offshore liability levy	Unit
Exempted	Exempted	Exempted	0.5	0.11	0.49	€/MWh withdrawn

[127] § 118 of the Energy Economy Act : http://www.gesetze-im-internet.de/enwg_2005/BJNR197010005.html#BJNR197010005BJNG002300000
[128] After their initial start-up or after the increase of capacity or output.
[129] https://www.amprion.net/Dokumente/Strommarkt/EEG/EEG-2017-Juris-Stand-13102016.pdf

5.4.3 Capacity remuneration mechanism

211. Germany plans to implement a strategic reserve mechanism for 2018[130]. Like for Belgium, it does not seem economically rational for a PHS plant to be procured as strategic reserve and to forego all profits on the energy and ancillary services market.

5.4.4 Frequency control reserves

FCR

212. FCR products are procured by the German TSOs thanks to the common European market. The demand of the German TSOs for FCR is equal to 603 MW in 2017[131]. Moreover, German FCR providers can offer their services abroad up to 181 MW[132]. The average price on this market is equal to 14.6 €/MW.h in 2017[133].

aFRR

213. aFRR products are procured through a national tender. Upward and downward products are procured separately. Moreover, in 2017, the German TSOs defined the products on a weekly basis with a distinction between peak and off-peak hours. Until 05/22/2017, peak products were defined for all days of a given week from 8am to 8pm (i.e. for 84 hours). Off-peak products corresponded to the remaining hours (00am to 8am and 8pm to 00am, i.e. for 84 hours). From 05/22/2017, peak products are defined for weekdays from 8am to 8pm (i.e. for 60 hours). Off-peak product correspond to the remaining hours (00am to 8am and 8pm to 00am for weekdays and all hours for weekends, i.e. for 108 hours).

214. The average prices and volumes for 2017 for each type of products are shown in Table 24.

Table 24. Average volumes and prices for aFRR in Germany in 2017[134]

	Upward	Downward
Peak hours	1,836 MW ; 2.20 €/MW.h	1,907 MW ; 0.12 €/MW.h
Off-peak hours	1,836 MW ; 2.70 €/MW.h.h	1,907 MW ; 1.30 €/MW.h

mFRR

215. mFRR products are procured through a national tender, with a distinction between upward and downward products. Moreover, the German TSOs procures these products through daily auctions. More precisely, products are defined on a 4-hour time slots (00am-4am, 4am-8am, 8am-12pm, 12pm-4pm, 4pm-8pm and 8pm-00am) for each given day[135]. Average volumes and prices for 2017 are depicted in Table 25.

[130] Cf. http://ec.europa.eu/competition/state_aid/cases/269083/269083_1890897_10_2.pdf
[131] Cf. results published on https://www.regelleistung.net/ext/
[132] Cf. https://consultations.entsoe.eu/markets/fcr-cooperation-potential-market-design-evolutions/supporting_documents/20170102%20FCR%20market%20consultation.pdf
[133] Cf. results published on https://www.regelleistung.net/ext/
[134] Cf. https://transparency.entsoe.eu/
[135] Cf. https://www.regelleistung.net/ext/static/mrl

Table 25. Average volumes and prices for mFRR in Germany in 2017[136]

	Upward	Downward
00am-4am	1,318 MW ; 0.00 €/MW.h	1,717 MW ; 1.41 €/MW.h
4am-8am	1,318 MW ; 0.02 €/MW.h	1,717 MW ; 1.30 €/MW.h
8am-12pm	1,318 MW ; 0.07 €/MW.h	1,717 MW ; 0.48 €/MW.h
12pm-4pm	1,318 MW ; 0.03 €/MW.h	1,717 MW ; 0.58 €/MW.h
4pm-8pm	1,318 MW ; 0.30 €/MW.h	1,717 MW ; 0.41 €/MW.h
8pm-00am	1,318 MW ; 0.01 €/MW.h	1,717 MW ; 0.47 €/MW.h

216. Thus, on overall, there are 42 different products upward for one week (and the same number downwards).

5.4.5 Voltage support

217. To the best of our knowledge, voltage control in Germany is not documented in the available documents published by the TSOs. However, according to the survey of ENTSO-E[137], this provision is agreed between the TSOs and each plant in the grid connection contracts (bilateral contracts). Moreover, this service is remunerated.

5.4.6 Black start

218. To the best of our knowledge, provision of black start services in Germany is not documented in the available documents published by the TSOs. However, according to the survey of ENTSO-E[138], TSOs procure this service through specific contracts which is remunerated.

[136] Cf. https://transparency.entsoe.eu/
[137] Cf. https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS_Survey_final_10.03.2017.pdf
[138] Ibid.

5.5 Country specific details: Great Britain

5.5.1 Transmission network charges in Great Britain

219. The British Transmission network is complex as three TSOs are operating it: National Grid (NG), Scottish Hydro Electric Transmission (SHP) and Scottish Power Transmission (SPT). The country is also divided into fourteen tariff areas for consumers directly connected to the transmission network and twenty-seven areas for producers directly connected to the transmission network.

220. As each area has a single value for its tariff, and as the demand areas do not exactly correspond to the areas for generators, the study presents a weighted average for the transmission charges applied in Great Britain. Each tariff is weighted by the size of the area, and the average is then computed at a TSO level.

221. The Transmission charges in Great Britain are fixed by OFGEM through the Transmission Network Use of System (TNUoS) and the Balancing Services Use of System (BSUoS).

222. TNUoS are divided into three main components:

a. The demand charge, which is a tariff applied on the peak capacity demand. The charge is calculated on TRIAD hours. The TRIAD are "the three half-hour settlement period with highest system demand. They can occur in any half-hour on any day between November to February but are separated each other by at least ten full days"[139]. Following the same reasoning than in Belgium, the study assumes that the modeled PHS is never consuming during these three half-hours and thus does not paid these demand charges.

b. The local Substation Tariffs, which are charges applied on the capacity for generators. These charges depend on the level of voltage of which the PHS is connected. The study assumes that the modeled PHS is connected to the highest voltage level.

c. The Wider Generation Tariffs, which are charges applied on the capacity for generators.

d. Table 26 summarizes the value of TNUoS average charges.

Table 26. TNUoS in Great Britain – weighted average

	Demand charges	Wider generation	Local substation
NG	Not paid by the modeled PHS plant	5,692.929 £/MW for injection	76.115 £/MW for injection
SHP	Not paid by the modeled PHS plant	16,455.46 £/MW for injection	76.115 £/MW for injection
SPT	Not paid by the modeled PHS plant	15,508.79 £/MW for injection	76.115 £/MW for injection

223. As of BSUoS, National Grid publishes BSUoS prices every year. Both producers and consumers pay them. The amount is calculated based on the electricity injected to and withdrawn from the transmission network. As data for BSUoS prices for 2017 are not yet published by NG,

[139] https://www.nationalgrid.com/sites/default/files/documents/44940-Triads%20Information.pdf

the study uses, for each year, the average value of BSUoS prices for the year 2016 (i.e. 2.6£/MWh both on injection and on withdrawal).

224. TNUoS and BSUoS do not take into account electricity losses in their tariffs. Therefore, OFGEM has developed a methodology in order to value these losses.

225. The current regulation introduces Transmission Loss Multipliers to scale up (respectively, down) the metered injected volumes (respectively, withdrawn volumes) of Balancing Mechanisms Units (BMU). For a balancing perimeter with a single injection unit and a single withdrawal unit, the balancing equation becomes:

$$BMU\ value_{pre-adjusted\ injected\ volume} * TLM_{injection} = BMU\ value_{pre-adjusted\ withdrawn\ volume} * TLM_{withdrawal}$$

226. The TLM is derived from the following formula: $TLM = 1 + TLF + TLMO$, with TLF the transmission loss factor (to differentiate the allocation of losses between several BMUs or areas) and TLMO, which ensures that the responsibility of both injection and withdrawal is taken into account.

227. Until 1 April 2018, TLF is equal to zero and a uniform locational allocation of losses is performed. Meanwhile, TLMO is computed as the product of an average transmission loss factor and the responsibility factor, which differs for injection and withdrawal:

For injection, $TLMO = average\ loss\ factor * (-45\%)$, with 45% the responsibility factor for injection
For withdrawal, $TLMO = average\ loss\ factor * (+55\%)$, with 55% the responsibility factor for withdrawal

228. For the present exercise, and following the publications made by British TSOs[140], an average loss factor of 2% is assumed. This yields the following TLM:

For injection, TLM = 1 – 0.009 = 0.991
For withdrawal, TLM = 1 + 0.011 = 1.011

229. Interpreting the balancing obligations of balancing perimeters in a simplified way, this means that the injection unit will only sell 0.991 MWh for each MWh produced. The rest will be used to cover estimated losses. This entails an extra-cost of **0.009** * selling price for each MWh injected into the grid. Meanwhile, each MWh withdrawn from the grid will cost an extra **0.011** * buying price.

5.5.2 Taxes and surcharges in Great Britain

230. The British regulation does not specifically define storage (i.e. as a consumer or a producer). In this respect, OFGEM launched a public consultation in early 2018 in order to assess the status of storage (including PHS) in the regulation.

231. Nonetheless, based on information provided by Engie UK, the PHS in Great Britain is exempted to pay all end consumers charges (i.e. the Renewable Obligation Certificate, The Climate Change levy and the AAHEDC). Therefore, the study considers that the modeled PHS does not pay these taxes and surcharges, as it seems to be the case in Great Britain for real PHS.

5.5.3 Capacity remuneration mechanism

232. Great Britain has implemented a capacity market. With this solution, a new market for capacity is created. On this market, a demand for capacity is defined by the TSO. Capacity providers (like generation plants, storage facilities, demand-response…) bid on this market. The volume they provide is determined by the regulator based on their installed capacity and on a derating factor. This derating factor reflects the contribution of each plant to the capacity

[140] https://www.nationalgrid.com/sites/default/files/documents/36718-Transmission%20Losses%20Strategy.pdf

requirement. To simplify, this factor expresses the probability the plant is available to produce during peak hours. For PHS plants, this factor is equal to 96.29%[141]. This high factor is notably explained by the low duration of peak periods considered for its computation. Indeed, capacity providers have to be able to produce during 4 hours a day only during peak periods which is possible for the modeled power plant in this study. Consequently, a 1000-MW can offer 963 MW on the capacity market. The price at which it will bid is chosen freely by the plant[142].

233. Based on the supply and demand curves, a capacity price is determined. For the period 2018/2019 (the first year for delivery), this price is equal to 19,400 £/de-rated MW/year[143]. This price is then considered in this simulation for the revenues from the British CRM.

5.5.4 Frequency control reserves

234. Frequency control reserves in Great Britain are significantly different from the ones traded in continental Europe. More than 10 different reserves products exist. Moreover, to the best of our knowledge, data about the past remuneration of these products is not available in the current literature (or very sparse).

235. Following discussions with ENGIE UK, it appears that the main reserves that a PHS plant can provide are:

a. Mandatory frequency response (MFR)[144]. These reserves can be divided into:

   i. Primary response, which must be activated in 10 seconds and sustained for a further 20 seconds.

   ii. Secondary response, which must be activated in 30 seconds and sustained for a further 30 minutes.

   iii. High frequency response, which must be activated in 10 seconds and sustained indefinitely.

   Large power plants are obliged to have the capability to provide these reserves. Moreover, these provisions are remunerated based on the submission price of the plant.

b. Firm Frequency Response (FFR)[145]. These reserves are defined on the same technical characteristics as the MFR. The FFR are notably open to MFR providers which want to offer more reserves. FFR is procured through a monthly tender and successful bids are remunerated.

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141 https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Capacity%20Market%20Auction%20Guidelines%201st%20Mar%202017.pdf

142 However, some constraints apply. For instance, the plant cannot bid at a level higher than 25 £/kW/year except in case of investment or major refurbished (in which case they can bid above the previous threshold but below the capacity price cap).

143 https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Capacity%20Market%20Auction%20Guidelines%201st%20Mar%202017.pdf

144 https://www.nationalgrid.com/uk/electricity/balancing-services/frequency-response-services/mandatory-response-services

145 https://www.nationalgrid.com/uk/electricity/balancing-services/frequency-response-services/firm-frequency-response

c. Fast Reserve[146]. This reserve must be activated within two minutes and sustainable for at least 15 minutes. FFR is procured through a monthly tender and successful bids are remunerated.

d. Short term operating reserve (STOR)[147]. Providers should be able to be activated within a maximum of 240 minutes, although response times within 20 minutes are preferable. These reserves are procured thanks to three competitive tenders each year.

5.5.5 Voltage support

236. Power plants connected to the transmission network with a generation capacity of over 50MW are required to have the capability to reactive power service (defined as Obligatory reactive power service – ORPS – by the British TSO)[148]. Above this minimum requirement, plants can also provide voluntarily Enhanced Reactive Power Service (ERPS) through a tender organized by the TSO[149]. In any case, provisions are remunerated, either at a regulated price[150] (for compulsory provision) or at a free price[151] (for non-obligatory provision).

5.5.6 Black start

237. Black start services are procured by the TSO thanks to bilateral contracts (it is not a mandatory service). These services are then remunerated[152].

[146] https://www.nationalgrid.com/uk/electricity/balancing-services/reserve-services/fast-reserve?overview
[147] https://www.nationalgrid.com/uk/electricity/balancing-services/reserve-services/short-term-operating-reserve-stor?overview
[148] https://www.nationalgrid.com/uk/electricity/balancing-services/reactive-power-services/obligatory-reactive-power-service?overview
[149] http://nationalgrid.prod.acquia-sites.com/uk/electricity/balancing-services/reactive-power-services/enhanced-reactive-power-service?overview
[150] https://www.nationalgrid.com/uk/electricity/balancing-services/reactive-power-services/obligatory-reactive-power-service?getting-paid
[151] http://nationalgrid.prod.acquia-sites.com/uk/electricity/balancing-services/reactive-power-services/enhanced-reactive-power-service?getting-paid
[152] https://www.nationalgrid.com/uk/electricity/balancing-services/system-security-services/black-start?getting-paid

5.6 Country specific details: the Netherlands

5.6.1 Transmission network charges in the Netherlands

238. First, it must be reminded that there is no PHS in activity on the Dutch perimeter. Therefore, the Netherlands has only been described in the study through the qualitative benchmark.

239. TenneT, the Dutch TSO, charges the transmission network tariffs in the Netherlands. The transmission tariff includes:

i. A transmission-related consumer tariff, which consists in a unit price per MW depending on the operating time of the users (i.e. > or < 600 hours of operating time). It is composed of:

(1) A fixed component in euros per year

(2) A charge based on the actual maximum capacity contracted per year (in €/MW per year for consumers)

(3) A charges based on the actual maximum capacity contracted per month (in €/MW per month for consumers)

240. Besides, the Netherlands have not applied energy-based tariffs since 2009 for Transmission and Distribution.

241. Table 27 summarizes the transmission network charges in the Netherlands for the EHV.

Table 27. Transmission network charges in the Netherlands

Fixed charges (€/year)	Capacity charges based on the actual maximum MW contracted per year (€/MW)	Capacity charges based on the actual maximum MW contracted per month (€/MW)
12,478.96	5,640	650

5.6.2 Taxes and surcharges in the Netherlands

242. Several taxes and surcharges are applied in the Netherlands for electricity consumers[153].

243. First, the Tax on electricity is applied. It is a surcharge, which varies according to the electricity consumption of the customer. The study assumes that the PHS is included in the category "more than 10 million of kWh – business" and thus pays the rate of this category.

244. Second, consumers in the Netherlands also pay a PSO for the subsidy of the storage of renewable energy. The study assumes that the PHS would also pay the tariff for the same category than the Electricity tax.

[153] https://www.belastingdienst.nl/wps/wcm/connect/bldcontentnl/belastingdienst/zakelijk/overige_belastingen/belastingen_op_milieugrondslag/tarieven_milieubelastingen/tabellen_tarieven_milieubelastingen?projectid=6750bae7-383b-4c97-bc7a-802790bd1110

245. Table 28 summarizes the value of these two taxes.

Table 28. Taxes and surcharges in the Netherlands

Electricity tax	**0.57 €/MWh withdrawn**
PSO for RES	0.194 €/MWh withdrawn

5.6.3 Capacity remuneration mechanism

246. There is no CRM implemented in 2018.

5.6.4 Frequency control reserves

FCR

247. FCR needs are partly procured by the Dutch TSOs thanks to the common European market. The demand of the Dutch TSO for FCR on this market is equal to 74 MW in 2017[154]. Moreover, Dutch FCR providers can offer their services abroad up to 100 MW[155]. The average price on this market is equal to 14.6 €/MW.h in 2017.

248. Besides, the Dutch TSO procures another FCR product, whose technical characteristics are exactly the same as the FCR product procured on the common European market. However, this second FCR procurement market is only open to Dutch FCR providers. On this second market, the demand of the TSO is equal to 33 MW in 2017[156]. The average price on this market is equal to 14.9 €/MW.h in 2017[157].

aFRR

249. In 2017, the Dutch TSO procures its needed volume of aFRR using different types of product. The first one is a yearly product. For the first semester, the TSO also used quarterly products. For the second semester, it used monthly products instead. Moreover, all these products are defined as symmetric. Associated volumes and prices are defined in Table 29.

Table 29. Average volume and prices for aFRR in the Netherlands in 2017[158]

	First semester of 2017	Second semester of 2017
Yearly product	170 MW ; 20.67 €/MW.h	
Quarterly product	170 MW ; 19.98 €/MW.h	/
Monthly product	/	170 MW ; 17.96 €/MW.h

[154] https://www.regelleistung.net/ext/
[155] https://consultations.entsoe.eu/markets/fcr-cooperation-potential-market-design-evolutions/supporting_documents/20170102%20FCR%20market%20consultation.pdf
[156] https://www.regelleistung.net/ext/
[157] Ibid.
[158] https://transparency.entsoe.eu/

mFRR

250. In 2017, the Dutch TSO procures its needed volume of aFRR using half-yearly and quarterly products in parallel. Moreover, these products are asymmetric. Associated volumes and prices are defined in Table 30.

Table 30. Average volume and prices for mFRR in the Netherlands in 2017[159]

	Upward	Downward
Half-yearly	175 MW ; 5.76 €/MW.h	100 MW ; 15.15 €/MW.h
Quarterly	175 MW ; 3.75 €/MW.h	100 MW ; 6.27 €/MW.h

5.6.5 Voltage support

251. To the best of our knowledge, voltage control in the Netherlands is not documented in the available documents published by the Dutch TSO. However, according to the survey of ENTSO-E[160], power plants whose capacity is higher than 5 MW has to be able to provide this service, which is remunerated.

5.6.6 Black start

252. Black start services are procured by the TSO thanks to bilateral contracts (it is not a mandatory service). These services are then remunerated[161].

[159] https://transparency.entsoe.eu/
[160] https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS_Survey_final_10.03.2017.pdf
[161] https://www.tennet.eu/news/detail/tennet-and-nuon-to-realize-black-start-facility-for-northern-netherlands/

5.7 Technical description of the modeled PHS plant

253. The table below summarizes the main characteristics of the PHS plant considered in the simulations. Electrabel provided all data for the study. Deloitte did not crosscheck the data. Deloitte cannot be held accountable of any use of these values and of the resulting estimations.

254. The plant is composed of five reversible turbines, which can all produce electricity or pump water into the reservoir (thus withdrawing/consuming electricity from the grid). For the sake of clarity, we refer to those reversible turbines as "turbine" and precise their functioning mode (producing or pumping/withdrawing/consuming) when appropriate.

Table 31. Technical characteristics of the PHS plant considered in the simulations

Name	Value	Description
D_max	200 MW/turbine	Maximal injection power per turbine
C_max	200 MW/turbine	Maximal withdrawal power per turbine
D_min	80 MW/turbine	Minimum injection power per turbine
C_min	200 MW/turbine	Minimum withdrawal power per turbine
Ramp	10 MW/s/turbine	Ramping capacity for a turbine already started and producing
Start_up_cost	200€ when producing 400€ when pumping	Starting costs in production/pumping mode
Start_up_time	2 min when producing 4 min when pumping	Starting time in production/pumping mode
Stock_max (MWh)	5555 MWh	Maximum storage capacity for the reservoir (corresponds to 5000 MWh injected to the grid taking into account injection yield)
Efficiency	90% in injection 83% in withdrawal	Yield of the plant when injecting/withdrawing
Other	• Contracting FCR and aFRR is done individually for each turbine and requires the turbine to be producing (for response time purposes) • Modulation is not possible when pumping • mFRR can be contracted only with a stopped or producing turbine (as modulation is not possible when pumping) • Bypass is enabled (the plant can produce with one turbine while withdrawing with others)[162]	

[162] This assumption is particularly heavy as continuous bypassing is not possible in real life and not possible at all in some plants.

5.8 Sensitivity analyses on participation to ancillary services

255. The outputs of the main simulations concern the case where PHS can only participate to the (DA) energy market and CRMs. Even if those simulations are theoretical[163], they are reasonably aligned with the reality observed for PHS in each country thanks to the simulations' accuracy with regard to the plant's economic decisions on the DA. The quantitative study has however gone several steps further and has in particular tested the impact that an idealistic theoretical participation to ancillary services would have on the gross margin.

256. The next two sets of simulations presented in this subsection are based on the same assumptions regarding the plant's characteristics and its behavior on the DA, but now consider the **possibility to participate to ancillary services under extreme and optimistic assumptions**[164]. **This set of simulations can only be used to perform a theoretical comparison between countries.** It cannot be used to look at the level of profitability of an existing PHS plant in a particular country. All profits and revenues are indeed highly overestimated and possibly distorted from one actual plant to another, from one country to another. This upper boundary is unrealistic because unreachable due to both technical and market characteristics. As shown hereafter in this subsection, this sensitivity analysis demonstrates that Belgium reaching a level playing field is not possible even with highly overestimated revenues from ancillary services.

On top of the optimistic assumptions on participation to ancillary services, several technical simplifications are considered to simulate the behavior of PHS when it can provide these services:

- The scope for quantification is reduced to the procurement of frequency reserves only. Voltage control and black start services are assumed to influence only marginally the behavior of the plant on the other markets and not to introduce discrimination between countries[165]. Furthermore, few quantitative data enable a comparison of their impact on profitability for the studied countries. The activation of frequency reserves is also excluded due to modeling' simplicity requirements[166] and lack of data.

- Frequency Containment Reserves (FCR) are expected to have minor effect on results (in particular since this product is the most harmonized one between studied countries) and are

[163] Indeed, for the sake of comparison simulations had to consider an idealized PHS plant identical in all countries. This idealized plant cannot be directly compared to actual storage means. In particular, the assumption of perfect foresight significantly overestimates the revenues on DA market.
[164] Such as full technical possibility to do hydraulic bypass or the assumption that the plant can earn 100% of the market without influencing its price (price-taker with no resilience). These extreme assumptions are unrealistic and therefore prevent any comparison of obtained profits with an actual PHS plant profitability. However, those assumptions were required to enable a comparison between countries, given the lack of available data. For example, not allowing bypass would have made the situation even more unrealistic than when overestimating participation in reserve, thus resulting in an insignificant comparison.
[165] In the case of France, where black start services are mandatory and not remunerated, a compensation is introduced in results to take into account the extra cost.
The assumption that net revenue is equal to zero is equivalent to the assumption that the remuneration of those services is set at opportunity that operators incur. This 'cost-plus' vision of black-start and voltage support remuneration seems reasonable according to Electrabel's teams and in light of the public communications on the Belgian approach; it should only impact marginally the order of magnitude of the results
[166] Indeed, the volumes of activation requested to the plant depend on several parameters, such as the imbalance trend of the whole system and the rules used by the TSO to activate reserves (merit-order, pro-rata…), which cannot be considered easily in the modeling. Moreover, it is difficult to assume that the plant can estimate correctly imbalances price in advance (the imbalances trend is already difficult to anticipate) and then optimize its production decisions knowing these prices. Finally, when not considering activations, potential revenues are disregarded in the simulations. However, these revenues are linked with associated costs which are also disregarded. For instance, if a procured PHS plant is activated upward by the TSO, it will earn from the upward activation but it has to pump more electricity afterwards (or produce less), resulting in costs.

simulated individually from the other frequency services for computation time purposes[167]. The results presented in appendix 5.8.2 with regard to their assessment show that they have a limited impact on the plant's profitability: the capacity to provide FCR only increases the gross margin by half a million euros at most compared to a DA only configuration, which is the same order of magnitude than the simulation's margin of error. Yet, they provide valuable information to complete the quantitative image on PHS profitability.

- Given the storage constraints of the modeled plant, it is assumed that the plant cannot participate to mFRR and RR products whose maximum duration of activation is more than 2 hours. According to operational return on experience from Electrabel, for products with more than two hours of activation , given the size of the reservoir considered for the modeled plant, the constraint on stock is so strict[168] than other production means (such as OCGT - open cycle gas turbine) are more efficient to provide such services. This results in PHS not providing mFRR product whose maximum duration of activation is more than 2 hours. This assumption restricts mFRR and RR provisions to France's mFRR and RR as well as Belgian mFRR Flex products. A sensitivity analysis considering all mFRR products with a relaxed stock constraint has been performed and leads to the same conclusions as those presented thereafter.

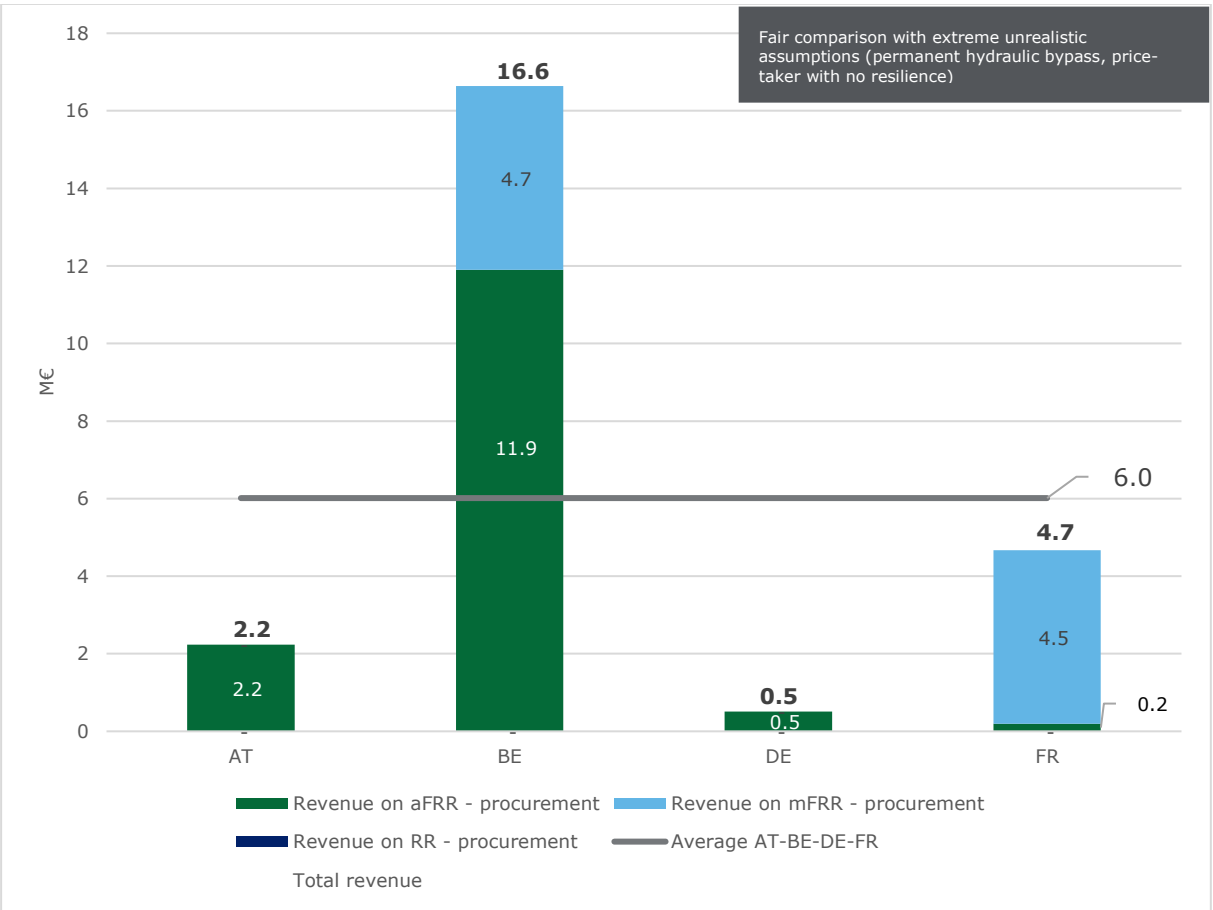
- Finally, the geographical scope has been reduced to Austria, Belgium, France and Germany, due to the lack of public data regarding the past price of British ancillary products.

5.8.1 Sensitivity analysis on participation to aFRR, mFRR and RR

257. As explained in the subsection's introduction, this benchmark enables a theoretical comparison of the idealized and overestimated gross margin of PHS modeled plants located in the Austrian, Belgian, French and German markets, assuming that they are able to participate to the corresponding national DA, CRM, aFRR, mFRR and RR mechanisms in the most optimistic, extreme, theoretical context. This gives a fuller picture regarding the highest level of gross margin that PHS could reach in each country, thus yielding higher margin levels compared to the DA only configuration. However, as already mentioned, the results presented hereafter have to be considered with extreme caution, because they show the theoretical unrealistic picture of a plant which has no technical or market constraint to provide ancillary services.

[167] Simulations without FCR already reach more than 10 hours of computation time.
[168] The plant must keep in stock the volume contracted multiplied by the maximum duration of activation to be sure it can be activated if the TSO requires it; this volume is then no longer available to perform arbitrages on the DA market. For example, for the mFRR standard product in Belgium whose maximum duration of activation is 2 hours a day, contracting 200 MW of these reserve implies to keep in stock 8*200 = 1600 MWh of stock, which represents a third of the maximum size of the reservoir.

Figure 9. **Breakdown of revenue from ancillary services procurement in an extreme optimistic context**



Quantitative benchmark – National markets – DA+CRM+ ancillary services aFRR, mFRR, RR – 2017

258. The first finding from the new simulation is that revenue from ancillary services greatly differ from one country to another.

a. Belgium benefits from the highest revenue with € 16.6 million euros, spread between aFRR (72%) and mFRR (28%). Those results are not so much surprising considering that (i) Belgian aFRR prices are really high compared to other countries[169] and (ii) the plant can perform bypass[170]. However, it can be surprising that despite its mFRR product not being flexible compared to other countries (products are defined on one month), associated revenue is very high.

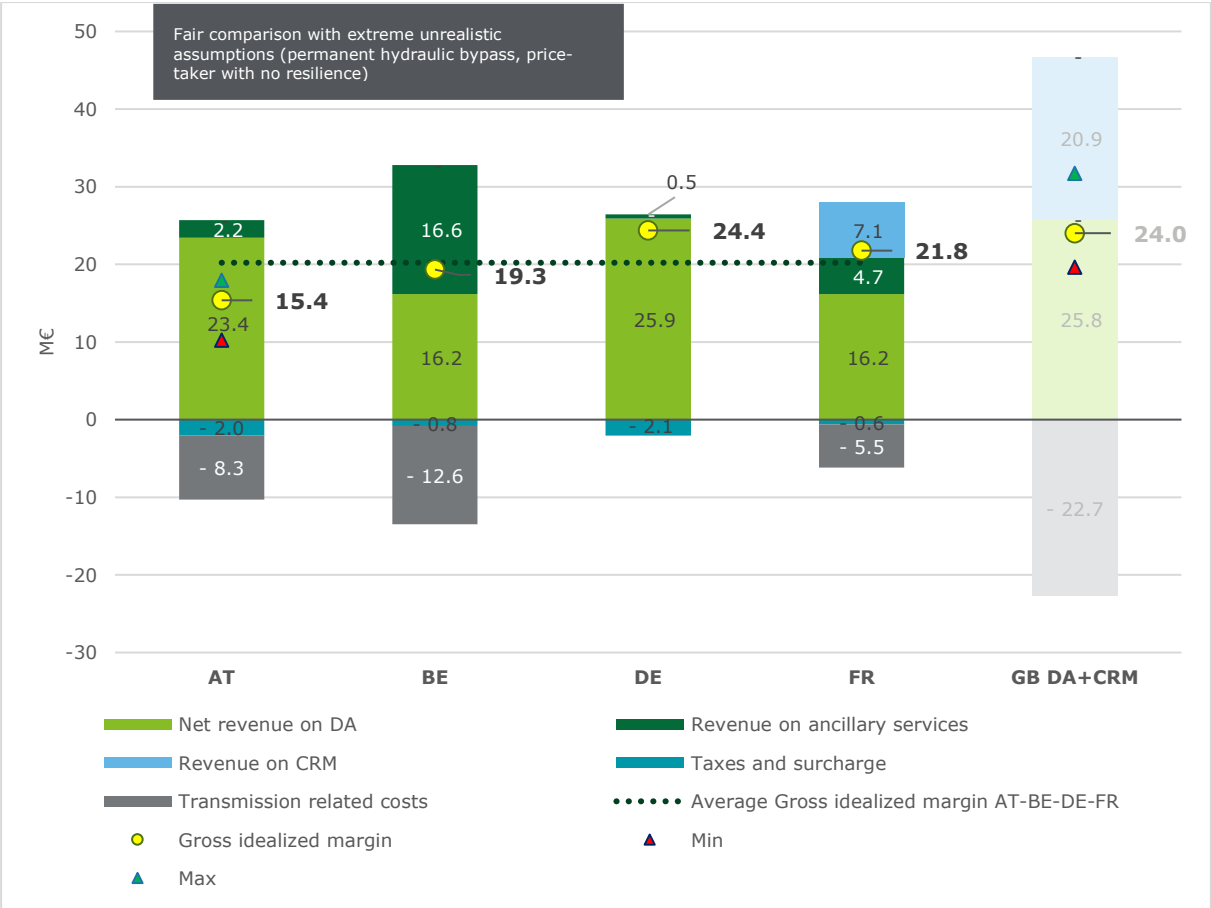
b. France is the following country in order of magnitude but still offers twice as less revenue - € 4.7 million. Contrarily to Belgium, the majority of revenue in France comes from mFRR (96%). The high revenue from mFRR in France can be explained thanks to decent prices (almost as high as in Belgium) combined with a limited maximum duration of activations (2 hours a day), like for the mFRR flex product in Belgium. Quasi-inexistent revenue from aFRR

[169] Average price in 2017 for upwards aFRR is 13.8 €/MW.h in Belgium, whereas it is 1.8 €/MW.h in Austria and 2.5 €/MW.h in Germany. The French case is particular as prices are high (18 €/MW.h) but the volume is drastically limited given the French TSO RTE splitting the required aFRR among all producing means proportionally to their current production.
[170] Hence pumping with some turbines while always running one turbine at 80 MW, enabling to provide 120 MW of aFRR upwards.

despite relatively high prices can be easily explained given the very low volume per plant imposed by French TSO RTE[171].

c. Austria and Germany provide opportunities only on aFRR due to the harder constraints to participate to mFRR[172], and these are rather limited, especially for Germany with only € 514,000. As previously explained, this result is coherent with the very low prices for those reserves compared to Belgium. Besides, combination of DA prices and network related costs in Germany shows a higher spread seen by the plant[173] than in Belgium. This results in more interest for the plant to keep all its capacity available to perform arbitrage in the DA market, hence not providing any reserve.

Figure 10. **Comparison of idealized gross margins when PHS can also provide aFRR, mFRR and RR in an extreme optimistic context**



Quantitative benchmark – National markets – DA+CRM+ ancillary services aFRR, mFRR, RR – 2017

259. Looking at gross margins where participation to frequency reserves is considered (figure 10), the results show that even a strong overestimated potential of revenue on ancillary services does not enable Belgium to reach a level playing field with France and Germany (and Great Britain by extrapolation[174]). Compared to the results with day-ahead and CRM only in section 3.2.1 (figure

[171] Ibid.
[172] Activation time in Austria and Germany for mFRR are above 4 hours, which makes those products unsuitable for PHS.
[173] The spread seen by the plant includes DA prices but also network charges as well as taxes and surcharges, those being very low in Germany given the exemption regime.
[174] Indeed, even without considering any ancillary services Great Britain already shows a gross margin of 24 M€, way above margins in Belgium. Adding ancillary services would result in increasing this gross margin (in the worst

3), the idealized gross margin in Belgium increases by 57% to reach € 19.3 million, but it is insufficient to reach the idealized gross margins in France and Germany, although they increased by far lower ratios (13% in France and only 1% in Germany). In any case, German PHS still is in a very favorable competitive situation compared to its neighbors. At the other end, Austria appears to lag behind with a gross margin of only € 15.4 million (8% increase), having not benefiting much from the ancillary services. However, the idealized gross margin is equivalent to the Belgian one in the most favorable regions of Vorarlberg and Tyrol.

260. Note that the provision of ancillary services leads to negative adjustments of the margins on the day-ahead, which will have in turn an impact on variable transmission costs and taxes. The plant will indeed change its decisions of injection and withdrawal in light of the opportunities for reserve procurement. For example, otherwise not interesting spreads on the DA could now become interesting because they open the possibility to provide very valuable reserve at a specific time, even if this implies for the plant to lose money on the DA at certain hours. In such a case, the volume will grow on the DA but the average earned spread will decrease, and the loss of revenue on DA will be more than compensated by the gains with ancillary services. At other times, the plant may decide that it is more interesting to provide reserves upwards than to inject; then the volume on the day-ahead will decrease; so will the earnings on the day-ahead.

Box 3. From idealized gross margin to an estimation of actual profitability – impact of reserves

In box 2 (section 3.2.1), it is explained how the realistic assessment and comparison of profitability requires to i) refine the modeling assumptions taken in the benchmark, which are very simplified for comparability reasons and ii) take into account the other operational costs (remaining operational (personnel, daily follow-up and maintenance, market dispatching, insurances …) and lifetime extension CAPEX (to ensure that the plant can continue to operate at full capacity)[175]. First simplified estimations show that these effects should not change the relative profitability levels of PHS in the studied countries, but they highlight financial difficulties in Belgium and Austria, where participation to only DA and CRM does not enable to cover all costs, thus threatening sustainability of existing PHS in those countries.

Using the sensitivity analysis' extremely optimistic results on revenue from ancillary services, one shows that ancillary services are vital to limit the risk of financial loss in both Austria and Belgium, but that they might remain insufficient anyway. In Austria in particular, a simplified estimation of profit before tax and depreciation yields a negative figure even in the most favorable regions (€ - 1 million). The country suffers from weak prospects on ancillary services even in the optimistic theoretical simulation. For Belgium, the results are marginally better, around € 2 million, but they stem from extremely optimistic values on ancillary services, which would indicate a negative value if more realistic modeling assumptions were considered.

This uncertainty of the benchmark's results to estimate Belgian PHS profitability and the intuition that existing PHS is not sustainable in the country justify the passage to a more realistic, accurate framework. This is the subject of the study's second note: 'Note on the realistic assessment of profitability for the Coo-Trois Ponts PHS plant'.

case, the gross margin would be the same), which means than Great Britain's profitability will remain higher than all countries but Germany for sure, and most probably higher than Germany too.

[175] Which amount to respectively 10 and 5 million euros for the Coo-Trois Ponts PHS plant.

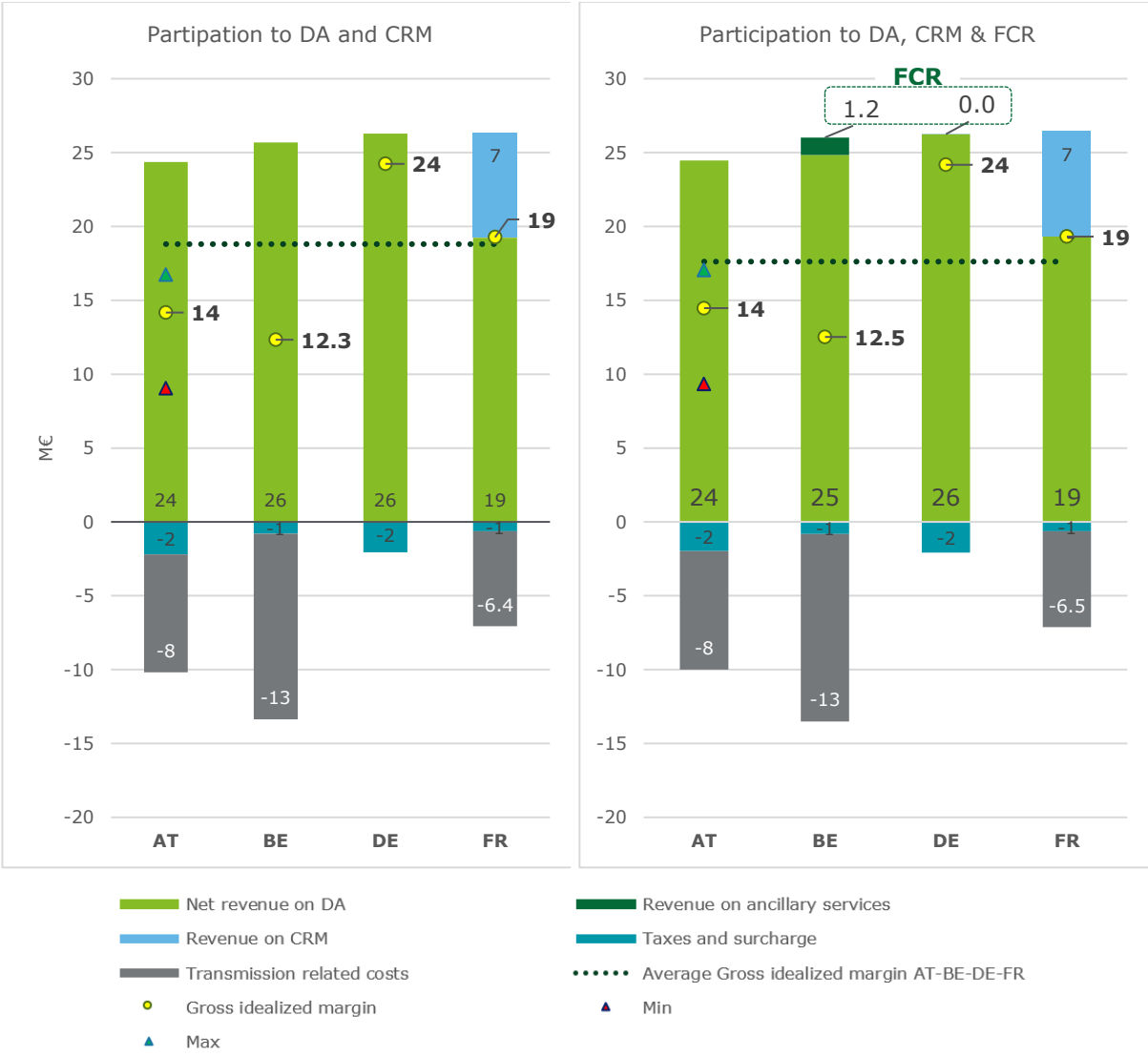
5.8.2 Sensitivity analysis of the participation to FCR

261. This subsection presents the results of the simulation of the modeled storage plant for the year 2017, assuming that the plant's operational choices and valuation options include arbitrage on the day-ahead (DA) market, the (eventual) CRMs, and the provision of Frequency Containment Reserves (FCR).

262. FCR are the first type of ancillary services related to frequency reserves, along with aFRR, mFRR and RR. The impact of those latter three is tested separately in the first sensitivity analysis in appendix 5.8.1. As a reminder, the separation of FCR from the other frequency reserves is due to computation time issues; it is also shown though the simulations that FCR has a limited impact on revenue compared to the other frequency reserves. A similar methodology of measurement of the marginal impact is however applied: the results with FCR are compared with the results when the plants can only participate to DA and CRMs (section 3.2.1). Note that as for aFRR, mFRR and RR, the geographical scope has been reduced to Austria, Belgium, France and Germany, due to the lack of public data regarding the past prices of British ancillary products.

263. In summary, this benchmark enables to compare the gross margin of PHS modeled plants located in the Austrian, Belgian, French and German markets, assuming that they are able to participate to the corresponding national DA, CRM and FCR mechanisms. The results confirm that revenue from FCR provision is marginal compared to the other frequency services.

Figure 11. **Comparison of idealized gross margins without and with FCR – Simulations for year 2017[176]**



Quantitative benchmark – National markets – 2017

264. The simulations of FCR participation show that decisions would be adjusted in Germany and Belgium. In Germany, the participation would be very limited and is negligible. In Belgium, revenue from FCR is more significant and the plant would earn up to € 1 million on this reserve mechanism, even if this would only results in an additional € 0.2 million gross margins, an amount comparable to the simulations margin of error.

265. The radical difference between Belgium and other countries is explained by the specific FCR product procured in the Belgian power system. Indeed, the common European market product (130-MW market size for Belgium in 2017) is complemented by a national FCR product (the R1 symmetrical 100mHz product, 18-MW market size on average) which auction average price is about twice higher (33.1 vs. 18 €/MW.h). This higher revenue outlook accounts for the decision by the Belgian plant to dedicate a turbine to provide this reserve.

[176] Great Britain is not included in the second series of simulations included ancillary services due to issues of data availability. However, one can assume from the results on the day-ahead and CRM simulation that the gross margin for GB would be higher than € 24 million if ancillary services were available: the British plant would still be in the most favorable position.

266. As a result, the Belgian idealized gross margin would be the only one to actually grow thanks to the participation to FCR. But this increase would remain limited because the participation to FCR is accompanied by a decrease of net revenue on DA (decrease due to 'negative' DA spreads that become necessary to ensure provision of FCR) by the same order of magnitude. The calculations show that the difference in gross margin between the two simulations (without and with FCR) is only about € 0.2 million. Given that the uncertainty of the simulations' outputs is + 200,000 €, this means that FCR participation would increase the Belgian gross margin by less than half a million at most. It is also worth being noted that this impact is a upper limit, due to the very optimistic assumptions for participation to FCR[177].

267. In conclusion, the participation to FCR appears to be only interesting with Belgium, when compared with France, Germany and Austria. But it would not lead to a significant increase in revenue, and therefore would not change the relative profitability position of each country: the idealized gross margin of the modeled Belgian PHS thus remains significantly lower than its neighbors (even including Great Britain, whose idealized gross margin without FCR is already € 24 million). With regard to the other frequency reserves (aFRR, mFRR, RR, whose impact for Belgium is a +57% increase of the idealized gross margin), FCR is thus marginal and would lead to negligible adjustments to the net revenue, would it be included in the main ancillary service quantification (see section 5.8). FCR would be insufficient to enable Belgium to catch up with France and Germany in the benchmark where participation to all frequency reserves is allowed. Indeed, assuming a maximum € 0.4 million revenue through FCR procurement, the idealized gross margin in Belgium would merely reach € 20 million, still far lower than the € 22 and 24 million in France and Germany[178].

[177] It is considered in the simulation that the plant can use hydraulic bypass, which allows a turbine to produce while others are pumping. This facilitates participation to reserve: without this option, providing FCR (which requires having a turbine producing to be able to react quickly) would mean emptying the reservoir without being able to refill it. It should be highlighted that in addition to being able to use bypass, there is no associated cost considered in the simulation.

[178] Note that these values correspond to the theoretical simulation of frequency reserves with the most extreme optimistic assumptions regarding PHS participation and provision or reserves. The results are purely indicative and do not reflect reality.

5.9 Sensitivity analysis on the years of simulation

268. This subsection presents the results of the simulation of the modeled storage plant for the years 2015, 2016 and 2017, assuming that the plant's operational choices and valuation options only include arbitrage on the day-ahead (DA) market and the (eventual) CRMs.

269. Compared to the main analysis in section 3.2.1, this enables to test the impact of annual DA spread profiles on the PHS gross margin, all other things being equal: the regulatory and fiscal frameworks and the CRM characteristics thus remain identical.

Figure 12. **Comparison of idealized gross margins for years 2015 to 2016 – Simulations with DA and CRM only**

Quantitative benchmark – National markets – DA+CRM

270. The test of idealized gross margins for DA price profiles in 2015, 2016 and 2017 show a high degree of variability. This is an expected result because the decisions of the plant as to DA spread arbitrage are directly related to the prices observed on the DA markets. Therefore, any variations in available spreads on the DA will modify the decisions of the plant to inject and to withdraw, and therefore its resulting revenue. All other things being equal, the higher the available spreads are on average (the higher or more frequent are peak prices, the lower or more frequent are negative prices), the higher the idealized gross margin of the plant will be.

271. The analysis of results shows that results are relatively stable for years 2015 and 2017 with regard to net revenue on DA and idealized gross margin.

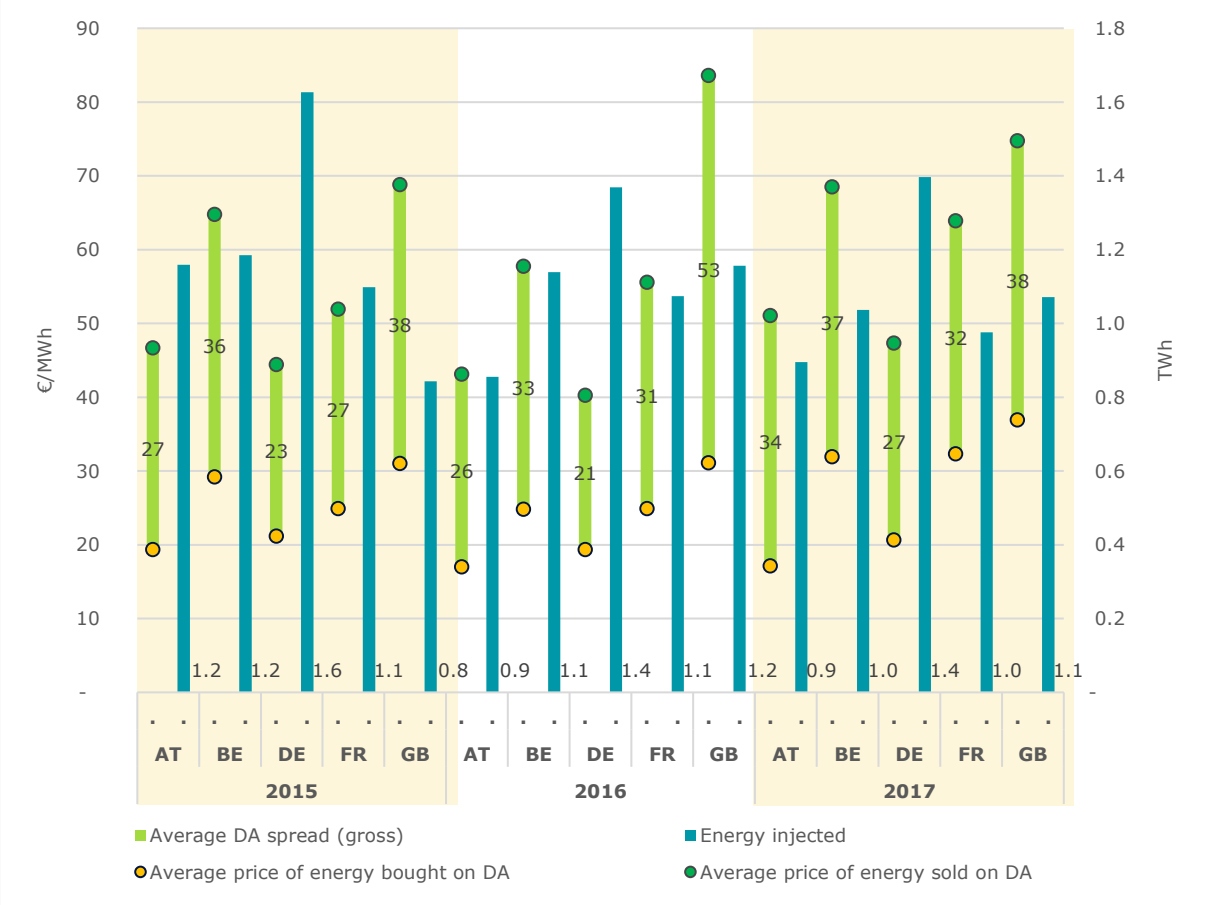
a. The variation in net revenue on DA are thus contained within a -12% / +18 % interval. This still represents high variation in earned revenue on the DA and gross margin. For example, the idealized gross margin in Belgium calculated for 2015 is € 3 million higher than the value for 2017.

b. Note however that this (relative) stability hides compensating effect between the average earned spread and the volumes exchanged on the DA. In France, the idealized gross margins measured for 2015 and 2017 are almost equal, but the underlying technical outputs are very different: 1.1 TWh injected and a 27 €/MWh average *earned* spread for 2015 versus 1.0 TWh injected and a 32 €/MWh average earned spread for 2017 (see figure 13). A second conclusion is thus that varying DA price curves can still lead to relatively close outcomes in terms of revenue and margin, as the level of prices can be compensated by the frequency of high spreads.

c. A similar reading of profitability drivers and gross margin shows that the volatility in net revenue from DA can be either compensated or multiplied when looking at the gross margins: indeed, the proportion of fixed or volume-based revenue and cost will upset the direct correlation between revenue from DA and gross margin. This is especially the case in Austria, where net revenue from DA increases by 6% between 2015 and 2017 but the idealized gross margin increases by 26%.

272. In contrast, the results for 2016 are substantially different from those in 2015 and 2017. On the one hand, idealized gross margins in Austria and Germany decrease by 40% and 26% between 2015 and 2017 (corresponding 28% and 25% decrease of net revenue from DA). For that specific year, Austrian PHS thus earns the lowest gross margin, on average € 6 million lower than in Belgium. Germany (€ 17 M) stays ahead of Belgium (€ 13 M) but far lower than France (€ 23 M). One the other hand, net revenue from DA in Great Britain jumps by 116%, which doubles the idealized gross margin between 2015 and 2016 (from 22 to 45 million euros). British PHS, which shows already the highest profitability in 2015 and 2017, here reaches an exceptionally high level of profit. Once again, these variations in revenue and margin are directly due to strong divergences in the observed price profiles on the DA. For Great Britain in particular, the peak prices were very high and very frequent, reaching more than 80 €/MWh (see next figure).

Figure 13. **Comparison of injected volumes and differences between average prices of energy bought and sold on the day-ahead market**



Quantitative benchmark – National markets – DA+CRM

Deloitte.

PARTENAIRE #FRANCE 2023

Deloitte.

Assessing the economic conditions of Belgian pumped-hydroelectric storage: comparative review of profitability drivers in Europe and evaluation of the current situation

Document 2 : Note on the realistic assessment of profitability for the Coo-Trois Ponts PHS plant

23 February 2018 – Final version

Strictly confidential

Prepared at the request of Electrabel

Table of contents

1 Introduction

1. The Belgian energy regulator CREG has recently launched a public consultation on the evolution of the transmission network charges (consultation 1718 on the « Projet d'arrêté modifiant l'arrêté (Z)141218-CDC- 1109/7 fixant la méthodologie tarifaire pour le réseau de transport d'électricité et pour les réseaux d'électricité ayant une fonction de transport »[1]). In particular, this consultation contains several proposals regarding the adjustment of transmission tariffs for storage facilities[2]. These proposals are based on a 2017 study by the Economic Advisory team of Deloitte France, comparing those tariffs in eleven European countries[3].

2. In this context, and after exchanges with the CREG on the content of the study, Electrabel mandated in December 2017 the same study team to continue the work on related questions, and more precisely to assess and compare the profitability drivers of an idealized pumped-hydroelectric storage (PHS) plant in Belgium and in its neighboring countries (Austria, France, Germany, Great Britain, Luxembourg, and the Netherlands). A complete benchmark report was written[4] as a first step of a general study on the economic conditions of Belgian PHS. It focused on the comparison of PHS profitability drivers in Belgium and neighboring countries. It is going to be published by Electrabel as part of its answer to the present consultation.

    a. The new benchmark took the point of view of a rational investor who wants to develop and operate a PHS plant in the countries where it is the most financially interesting. The scope considered the following profitability drivers: (i) revenues from the day-ahead market, (ii) revenues from the provision of ancillary services, (iii) revenues from capacity remuneration mechanism, (iv) transmission network charges and other costs related to the use of the electricity transmission network (loss compensation, other obligations…) and (v) taxes and surcharges on electricity.

    b. Simulations were performed to assess the decisions and arbitrages of the PHS plant in each country which maximize its annual profit. In particular, the quantitative benchmark considered an idealized PHS plant with some extreme assumptions (e.g. perfect foresight, price taker, capacity to perform hydraulic bypass). These assumptions were taken to simplify the simulations (and the associated computation time) and/or because of the unavailability of some inputs parameters. The idealistic simplifications were also required to draw quantitative elements of comparison between countries, all other things being equal.

    c. Based on the simulations, it appeared that the profitability drivers are the least favorable in Belgium, and that there is no level playing field for PHS plants in the studied countries. Even with extremely optimistic assumptions as to the participation to frequency services, Belgium cannot compete with the other countries, especially with regard to France, Germany and Great Britain where the idealized gross margins (i.e. before operational and maintenance costs) are several millions higher. This absence of level playing field is mainly explained by

[1] http://www.creg.be/fr/consultations-publiques/projet-darrete-1718-modifiant-larrete-z141218-cdc-11097-fixant-la
[2] The regulator proposes 1) a full exoneration from the network costs to new storage plants during 10 years; and 2) a 80%-exoneration for existing storage plants during five years provided that they undertake improvement works to increase their installed capacity and the size of their reservoir by 7.5%.
[3] *Comparison of Belgian transmission network costs incurred by an idealized storage facility with those in other European countries*, 2017. Deloitte. Available as appendix of the aforementioned consultation.
[4] *Comparative study of profitability drivers for pumped-hydroelectric storage in Western Europe*, 2018. Deloitte

the importance of the transmission tariffs paid by the Belgium PHS plant which burden its profitability.

3. In summary, the benchmark report commissioned by Electrabel illustrates the absence of level playing field between PHS plants located in and around the Belgian market. The profitability drivers are in general detrimental to the ability of Belgian PHS to compete with PHS in other countries for attracting new investors. The validity of those conclusions is made possible thanks to the theoretical framework which was applied, which assumes identical technical conditions and behaviors of the operators in all studied countries, and which is adapted to tackle all computation and data limitation issues. However, this very framework prevents from looking more precisely at the economic situation of an actual PHS plant. The assumptions which were taken were necessarily highly theoretical in order to highlight the main differences and levels of attractiveness between countries, but they are no longer valid when one looks to calculate realistically the level of profitability of an actual plant. For example, assessing the profitability of Electrabel's PHS plant at Coo-Trois Ponts requires to discard the ability to do hydraulic bypass, for which operational constraints are too strong to consider it possible on a regular basis. In this case, the plant's revenue on ancillary services should be almost null, in particular for reserve products with long procurement periods[5]. Conversely, if the plant is integrated within a portfolio, as is the case for the Coo-Trois Ponts plant with the Electrabel's asset portfolio, provision of reserves is mutualized and the PHS plant has more flexibility to provide them.

Objectives of the additional work

4. The present note summarizes the content and the results of an additional work which was realized by the study team of Deloitte France for Electrabel, in complement to the benchmark report and as part of the common study on the economic situation of Belgian PHS. The main objectives of the new work is to tackle the limitations of the theoretical benchmark framework, and to investigate further the actual profitability drivers of the PHS plant of Coo-Trois Ponts. This entails refining the idealistic assumptions of the theoretical framework, considering instead more accurate characteristics of the power plant and of the operator (e.g., imperfect foresight or the participation to ancillary services through Electrabel's portfolio).

5. More precisely, the additional research work is focused on adapting the simulations' assumptions in order to reproduce as accurately as possible the reality of a Belgian PHS plant similar to that of Coo-Trois Ponts[6], in terms of technical and economic behavior as well as earned revenue. The new results are thus intended to complete the first orders of magnitude of the main benchmark report on storage profitability in Belgium. They are key to the present consultation and to Electrabel, as they enable to get a more realistic view on the profitability prospects of Belgian PHS, and to conclude more surely on the ability of the Coo-Trois Ponts' plant to carry out new investments.

6. The remaining of this note is structured as follows: in the next section, the general methodology is described. It is based on the simulations developed in the main benchmark study, with several assumptions now challenged and refined to approach the real technical and economic situation of the Coo-Trois Ponts plant. Then, results from the new simulations are presented, along with a new and more accurate appraisal of Belgian PHS profitability.

[5] For instance, for a weekly product, the provision of aFRR by the PHS plant would require the plant to continuously produce at least at its minimum output for one week (since it cannot provide these reserves while being offline or while pumping). Moreover, due to the impossibility of performing hydraulic bypass, the plant would not be able to pump during one week which would ultimately result in the impossibility to produce to provide reserve.
[6] Nevertheless, the reader should note that the aim of this note is not to compute the exact profitability of the Coo-Trois Ponts plant, but of a comparable plant which could exist and present the same main economic features. In particular, several simplifying assumptions are still required, either regarding the technical characteristics of the plant or regarding the operator' behavior.

2 Methodology

2.1 Summary of assumptions of the first study

7. In the first part of the study (benchmark report), simplifying assumptions were required to enable a fair comparison between different countries. In particular, they took into account the differences in data availability from one country to another. They were also designed to represent a generic, idealistic plant which could exist in each country and which does not represent a particular existing asset.

8. The modeled plant had a rational behavior and sought to maximize its profit, performing energy arbitrage in the day-ahead market as well as providing ancillary services for frequency regulation[7]. Furthermore, the plant was considered to be price-taker (the plant's bids do not affect prices) and omniscient: it performed the profit maximization over the whole year knowing in advance all prices. Finally, the plant was on its own, as opposed to part of a portfolio, which implies that for reserve procurement the plant had to be able to provide reserve for the whole procurement period. From a technical point of view, it was also considered that the plant could perform hydraulic bypass, *i.e.* inject and withdraw electricity at the same time with different pumps/turbines. This assumption, which is very strong, was nevertheless mandatory as without it a plant on its own could not provide reserve in most countries, thus weakening the comparison.

2.2 Additional assumptions to approach the reality of Coo-Trois Ponts

9. The objective of this additional study is to better calibrate the simulations' assumptions in order to approach the actual features, behaviors and profitability outlook of the Coo-Trois Ponts PHS plant. However, it should be noted that the work does not aim to reproduce exactly Coo's technical, economic and financial characteristics: this would have required more extensive modeling of an existing plant with a history of operational decisions and events, and many specific details to take into account. Therefore, the exercise remains theoretical but seeks to get as close as possible to the reality of Coo-Trois Ponts, within a certain number of remaining simplifying modeling assumptions. In the rest of the document, one therefore mentions *the modeled plant* or *the plant*.

10. Among the assumptions that do not change between the benchmark and this second analysis, one should mention the quantification of other revenue from ancillary services:

    a. The activation of frequency reserves is not considered for the sake of simplicity[8].

[7] Black start services and tension regulation services were not analysed quantitatively due to the lack of available data.
[8] As a reminder from the benchmark report, the volumes of activation requested to the plant indeed depend on several parameters, such as the imbalance trend of the whole system and the rules used by the TSO to activate reserves (merit-order, pro-rata…), which cannot be considered easily in the modeling. Moreover, it is difficult to assume that the plant can estimate correctly imbalances price in advance (the imbalances trend is already difficult to anticipate) and then optimize its production decisions knowing these prices. Finally, when non considering activations, potential revenues are disregarded in the simulations. However, these revenues are linked with associated costs which are also disregarded. For instance, if a procured PHS plant is activated upward by the TSO, it will earn from the upward activation but it has to pump more electricity afterwards (or produce less), resulting in costs.

b. It is assumed that the net revenues from the provision of voltage support and of black start are equal to zero and there are not considered in the modeling. This is equivalent to the assumption that the remuneration of those services is set at the opportunity cost that operators incur. This 'cost-plus' vision of black-start and voltage support remuneration seems reasonable according to Electrabel's teams and in light of the public communications on the Belgian approach[9]; it should only impact marginally the order of magnitude of the results.

2.2.1 Modeling a plant within a portfolio

11. The first major change to the previous assumptions concerns the plant's operation by Electrabel. While the plant was previously completely independent and operated on its own, it is now assumed to be operated by Electrabel, which also owns a large part of the Belgian production mix. This changes the plant's operational decisions, in particular regarding the provision of reserves. Indeed, belonging to a portfolio gives more flexibility to the plant: it does not have to provide reserves for the whole procurement period (for instance the week for aFRR products) since other assets within the portfolio can replace it for some hours. In reality, Electrabel provides reserves on a portfolio basis and then allocates those reserves to specific assets on a daily basis, depending on the associated costs and the technical requirements.

Reserve procurement in a portfolio

12. According to close discussions held with Electrabel's team operating Coo PHS plant, the level of reserves that the modeled PHS plant can provide is determined as follows:

    a. For FCR and aFRR, the level of reserves that the PHS plant can provide is determined in two steps.

        i. First, the plant optimizes its injection and withdrawal decisions based on the arbitrage it can make on the day-ahead market, without considering the provision of reserves. This first optimization determines for each hour whether the plant will produce, consume or be offline.

        ii. In a second step, the provision of FCR and/or aFRR is considered. If the plant was due to produce, it can reduce its volume to provide reserves, provided that it is economically relevant to do so. Otherwise, it does not change its previous decisions and keeps pumping or remains off-line, as set in the initial arbitrage. In this case, the plant does not provide reserves[10].

    b. For mFRR (R3 in Belgium), according to Electrabel, the opportunity costs of providing these reserves with the PHS plant are always higher than those of other assets of the portfolio, such as open cycle gas turbines. Then, if Electrabel has committed to provide mFRR, it will actually provide them with thermal plants rather than the modeled PHS plant. Consequently, it is assumed that the modeled plant can no longer provide mFRR to reflect the current reality in Belgium.

[9] In 2015, the CREG assessed that prices asked for some offers were unreasonable. As a result, the Ministry of Energy published decree projects that would fix volume and price conditions. See the CREG's opinion for these projects here: http://www.creg-ar.be/2015/images/pdf/CREG-AR-2015_fr_%C3%A9lectricit%C3%A9.pdf
[10] It was assumed that the plant cannot provide reserves while pumping. This assumption is kept here since it represents the reality.

Underlying assumptions

13. Several assumptions are implicitly made when considering this behavior of the portfolio and of the PHS plant.

    a. First, it is assumed that if the modeled plant cannot provide reserves (for example since it is pumping), another asset within the portfolio will replace it: Electrabel can then provide the exact level it committed to provide in the procurement market.

    b. Second, it is assumed that the modeled plant has some level of priority to provide reserves compared to Electrabel's other assets. Indeed, if the provision of reserves is not economically interesting for Coo (for instance if it prefers to produce on the day-ahead market), it does not have to provide them and another plant within the portfolio will do it, whatever the associated costs. On the contrary, when it is interesting for the PHS plant to provide reserves, it can provide the whole level procured by Electrabel, regardless of the associated costs of other assets. This is an optimistic assumption and tends to increase the plant's profit compared to reality.

Reflecting competition within Belgium

14. To reflect the current Belgian competition, 2017 market shares of Electrabel for the different types of reserves is considered. For several weeks, Electrabel did not provide any reserves (since other producers were more competitive); therefore the PHS plant cannot provide reserves either for these periods in the simulation.

Remuneration associated to reserve procurement

15. As for the remuneration price for the provision of reserves, according to the current practice within Electrabel's portfolio, it is considered that prices paid to the PHS plant are equal to the average procurement price for the whole procurement period.

2.2.2 Technical assumptions

16. From a technical point of view, it is no longer considered that the modeled plant can perform hydraulic bypass. Indeed, given the strong operational constraints associated with turbines of Coo plant, this former assumption seems to be unrealistic.

2.2.3 Accounting for imperfect foresight

17. Finally, the simulations of this study tackle the issue of perfect foresight. While in the first study the plant knew in advance the real day-ahead prices, here the optimization is performed with forecasted prices[11], thus reflecting the non-omniscience of the plant.

[11] Forecasted prices are provided by Electrabel and reflect their day ahead price forecast in 2017.

3 Results

3.1 Description and interpretation of the simulation's results

18. As explained in the previous section, the results in this new work are obtained through a realistic simulation, for year 2017, of a PHS plant which is similar to Coo-Trois Ponts in terms of technical parameters, economic characteristics and location. In particular, the modeled plant has the following features:

    a. It is located in Wallonia. It is connected to Elia's transmission network at the highest voltage level.

    b. The operator of the plant does not have a perfect foresight of future day-ahead prices. It optimizes its decisions based on the price forecasts used by Electrabel.

    c. It cannot do hydraulic bypass.

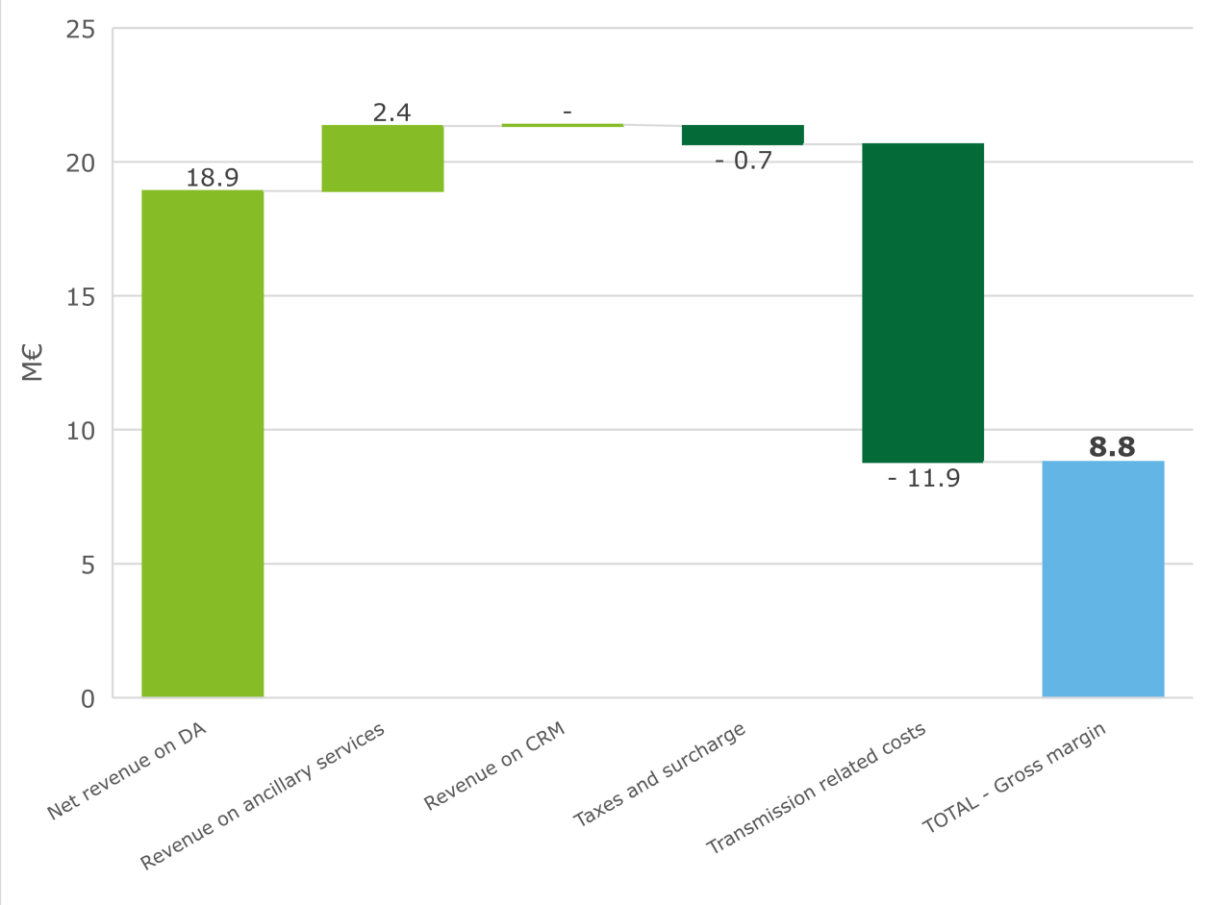
    d. It is always available. There is no maintenance work that would require adjusting the operation of the plant.

    e. It is part of Electrabel's portfolio, enabling the plant to participate in reserve markets despite not being able to perform hydraulic bypass.

19. Applying this realistic set of assumptions, the gross margin of the plant is € 8.8 million (see figure 1 hereafter). It is significantly lower than figures calculated in the main benchmark report, confirming the very optimistic and unrealistic assumptions regarding perfect foresight and hydraulic bypass[12]. In particular, the simulations have shown that the passage from 'perfect' to 'imperfect' foresight leads to a 25% decrease of net revenue on the day-ahead energy market[13]. The net revenue on DA in the realistic simulation is therefore € 18.9 million. Note that this estimation remains optimistic, because other elements (such as some offers being paradoxically rejected – see box 1) were not taken into account and should in reality decrease even more the share of idealized DA revenue that the plant could earn.

[12] As a reminder, the idealized gross margin for Belgium was assessed at € 12.3 million in the DA-only, perfect foresight scenario, and at € 19.3 million in the theoretical scenario where the plant could also participate to aFRR and mFRR under the most extreme optimistic assumptions. The lowest value observed now in the realistic simulation reflects the significant impact that refining major assumptions can have on the simulated margins, and confirms that the previously measured margins were highly overestimated.
[13] This represents around € 6 million decrease. Multiple simulations performed show that this 25% decrease of the DA net revenue is stable regardless of the possibility for the plant to provide reserve.

Figure 1. **Distribution of the gross margin with realistic assumptions approaching the conditions of Coo-Trois Ponts**



Realistic simulation of a plant similar to Coo-Trois ponts – year 2017

20. In the realistic simulation, the revenue from providing frequency reserves is now € 2.4 million. 90% of this revenue comes from aFRR (€ 2.2 million, well distributed between upward and downward reserve), and the remaining 10% are from FCR. These numbers were commented by Electrabel's teams working on Coo-Trois Ponts as close to reality. The outcome is logical given the realistic assumptions considered in this additional work[14].

21. The third main driver of the plant's gross margin remains transmission related costs, which still represents almost € 12 million. These costs are very stable with previous simulations because they consist mainly of capacity-based tariffs, which represent around € 8 million. The remainder

[14] Compared to the theoretical exercise in the benchmark report, the refined assumptions made here affect in opposite ways the ability for the modeled plant to provide reserves.
First, the impossibility to perform hydraulic bypass prevents the plant from providing FCR or aFRR on its own, and then reduces the associate revenues all other thing being equal . Indeed, to provide FCR or aFRR in Belgium, the plant must have at least one turbine already producing during the whole procurement period (the week), at the minimum power level of 80 MW. Calculations show that this would require a stock twice as high as the plant's reservoir size.
Second, the consideration of the plant within the portfolio of Electrabel enables it to provide reserves on an hourly basis, and not for the whole procurement period. This tends to increase the revenues from the reserves provision since the plant has more flexibility to provide reserves, all other things being equal.
Third, regarding the volume the plant can provide, revenues decrease compared to the first study since the plant cannot provide the whole demand asked by the TSO. For FCR and aFRR, the volume procured by Electrabel on the reserves market in 2017 limits the maximum volume the modeled plant can provide. For mFRR, it is assumed that the plant does not provide them since other assets within the portfolio are less costly.

being energy-based, it also affects negatively the ability of the plant to access all the economically positive spreads on the energy market.

Box 1. Remaining simplifying assumptions which tend to overestimate revenue

Even if the new set of assumptions makes the simulation closer to Coo's operational reality, some simplifying assumptions remain due to modeling and data limitations, **resulting in an overestimation of Coo's revenue and profit**.

As already stated, the plant is assumed to have the priority within Electrabel's portfolio to provide reserves when it is interesting. In reality, Coo may be unable to provide reserve even if it would be interesting (for instance, if cheaper solutions within the portfolio exit); conversely, the plant may have to provide reserves during some hours even if it would be more interesting for the PHS plant to produce in the DA market. Moreover, the impact of the plant's bid on day-ahead prices is only partially considered in the simulation and not accurately modeled. Also, the simulation does not include the possibility of paradoxically rejected offers: it is assumed that when the modeled plant bids to produce with a price lower than actual clearing price, its offer is always accepted by the market operator. In reality, complex bids are submitted, reflecting the technical constraints of the plant (for instance linking a supply bid with a demand bid to respect the stock constraint): due to these constraints, these bids can be refused by the market operator even if they are submitted at a price lower than the market clearing price. It then creates foregone revenues for the plant which are not considered in the simulations. Another major optimistic assumption concerns the full availability of the plant: its operation is never interrupted or affected by maintenance work or other events during the simulated year.

All in all, even if the new assumptions are closer to reality, they still contain some simplified assumptions and those tend to overestimate the plant's revenues, all other things being equal.

3.2 Appraisal of the plant's level of profitability

22. Profitability (before depreciation and income tax) is obtained from the gross margin by subtracting the remaining operational (personnel, daily follow-up and maintenance, market dispatching, insurances …) and lifetime extension CAPEX (to ensure that the plant can continue to operate at full capacity). Figures communicated by Electrabel have placed these two additional cost components around respectively 10 and 5 million euros a year for Coo-Trois Ponts[15]. Cumulated, this amounts to almost twice as much as the gross margin calculated through the realistic simulation. As a result, one can estimate that under realistic economic assumptions the Coo-like PHS plant is hardly able to cover its remaining operational costs, and is unable to launch and ensure lifetime extension works needed to operate at full capacity (see Figure 2). The plant would be at risk of not being resilient to major breakdowns.

[15] Source: Electrabel internal analysis. The data was not crosschecked by Deloitte. Deloitte cannot be held accountable of any use of these costs and of the resulting estimations

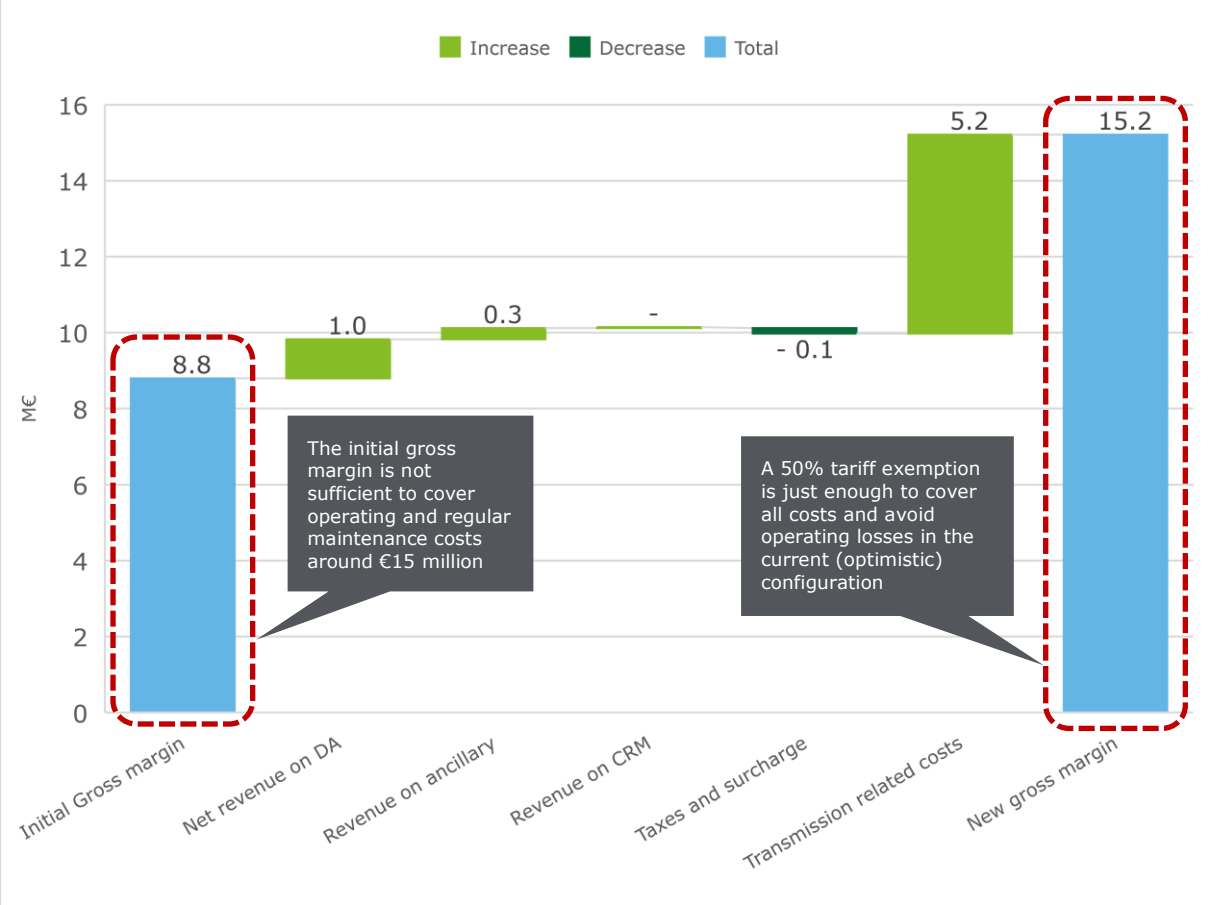
Figure 2. **Comparison of the gross margin for the Coo-like station with the other operational and lifetime extension costs experienced in Coo-Trois Ponts (2017)**

Realistic simulation of a plant similar to Coo-Trois ponts – year 2017

23. The financial difficulty to cover operational and lifetime extension works puts into question the sustainability of the plant, both in the short and long terms. It also give very pessimistic signals to investors which would be interested to modernize and retrofit the plant: any eventual return on investment would serve in priority to compensate the existing operating loss and to launch urgent maintenance work.

24. In this critical context, the tariff exemption envisaged in Belgium by the CREG can be actually perceived as the answer to two policy objectives. The first objective is to ensure the operational sustainability of existing Belgian PHS, which requires a positive net operating result that is not currently verified. To reach this objective, simulations show that a (unconditional, simultaneous and permanent) 50% exemption rate would enable to cover the annual level of operating and recurrent maintenance costs for the Coo-like modeled plant (see figure 3). The second objective, indeed highlighted in the consultation document, is to encourage investments, both for new projects and existing plants. But this second objective cannot be tackled without addressing the first, *i.e.* ensuring the financially viable operation of existing PHS in the country. Therefore, to reach the desired policy objectives regarding storage deployment and use, the eventual level of tariff exemption and the conditions for eligibility could be calibrated to both ensure the financial sustainability of existing PHS plants and to attract the targeted additional investment levels.

Figure 3. **Distributed impact on gross margin of a 50% tariff exemption (immediate, unconditional and permanent)**



Realistic simulation of a plant similar to Coo-Trois ponts – year 2017

4 Conclusion

25. In complement to the main benchmark report which found an absence of level playing field between PHS plants located in and around the Belgian market, this additional study investigates further the actual profitability drivers of a PHS plant located in Belgium. Indeed, the idealistic and theoretical assumptions made in the first benchmark prevents any conclusion on the economic situation of an actual PHS plant. The refinement of major simulations' assumption now enables to appraise more accurately the reality of a Belgian PHS plant similar to Coo-Trois Ponts (e.g. impossibility to perform hydraulic bypass, imperfect foresight on prices or the participation to Electrabel's portfolio of ancillary services providers).

26. With this more realistic set of assumptions, the gross margin of the modeled Belgian plant is € 8.8 million. Its main source of revenue by far is the day-ahead market (€ 18.4 million), while provision of frequency reserves (FCR and aFRR) brings additional € 2.4 million, in line with the observations made by the team responsible for Coo. As in the benchmark report, transmission related costs are a major profitability burden. They amount to € 11.9 million. Ultimately, the gross margin appears to be insufficient to cover the remaining operational costs (personnel, insurances, market dispatching, daily follow-up and maintenance, …, estimated at € 10 million by Electrabel). Electrabel is then unable to perform lifetime extension works needed to keep on operating at full capacity (these works would amount to an additional € 5 million annually on average, according to Electrabel).

27. This critical situation regarding the current operation of PHS plants puts into question the sustainability of existing PHS in Belgian. It excludes any possibility for new profitable investments on the current assets. In this critical context, the tariff exemption envisaged by the CREG should not be seen only as an incentive to promote new retrofit and deployment investments. Above all, it could be considered as the answer to ensure sustainability of existing Belgium storage. The level of the exemption could then be calibrated to guarantee those two objectives: ensuring the operational sustainability of existing PHS <u>and</u> encouraging new investments in the sector.

Deloitte.

PARTENAIRE #FRANCE 2023

Assessing the economic conditions of Belgian pumped-hydroelectric storage: comparative review of profitability drivers in Europe and evaluation of the current situation

Joint executive summary – 23 February 2018
Final version

1. Despite the recognized value of energy storage for flexibility or peak shaving, its commercial development remains limited due to the persisting presence of market or regulatory barriers (technical constraints for participation to ancillary services, double counting of charges on both injection and withdrawal…) as well as limited opportunities to benefit from the spreads on energy markets. A dynamic wave of reforms is now taking place throughout Europe to tackle these issues and help place storage at the center of opportunities on the energy market along with demand response and generation. Several European countries have already adapted their regulatory framework to enable a more massive development of storage and to secure operation of existing assets.

2. In Belgium, several recommendations were made as soon as 2015 by the energy regulator CREG to encourage storage development, targeting in particular the economic barriers linked with network tariffs. They were followed by an amendment of the Belgian Electricity Law[1], which exonerates storage facilities from the federal levy and also gives the CREG the possibility to create a special tariff regime for storage. In this respect, the CREG commissioned in June 2017 a study comparing the transmission network costs incurred by storage facilities in eleven European countries[2]. The study was carried out by the Economic Advisory team of Deloitte France and was the basis of the CREG's proposals for a specific tariff regime in the current public consultation on the evolution of transmission network charges[3]. In this context, Electrabel mandated the same study team to continue the work on questions regarding the economic conditions of Belgian pumped hydro storage (PHS) compared to the neighboring countries.

3. This new study focuses on assessing the current profitability level of Belgian PHS and its competitive position compared to its neighbors, from the point of view of private operators and investors aiming to build the most competitive portfolio of assets throughout Europe. The focus on PHS is of significant importance for Electrabel, which operates the largest pumped storage facility in Belgium (Coo – Trois Ponts). It is also highly relevant as PHS remains the most mature and available storage technology in Europe.

4. The study is divided into two complementary steps. First, a qualitative and quantitative benchmark is performed. It aims at identifying and comparing the costs and revenues that a private operator of PHS would experience in Belgium and the neighboring countries with which it is highly coupled: Austria, France, Germany, Great Britain, Luxembourg and the Netherlands. The results are used to assess the existence (or lack thereof) of a level playing field for PHS

[1] *"13 Juillet 2017. — Loi modifiant la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité en vue d'améliorer la flexibilité de la demande et le stockage d'électricité"*. See the document available here: http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=fr&la=F&table_name=loi&cn=2017071306

[2] "Comparison of Belgian transmission network costs incurred by an idealized storage facility with those in other European countries", available as appendix of consultation 1718 (see next footnote).

[3] Consultation 1718 on the « Projet d'arrêté modifiant l'arrêté (Z)141218-CDC- 1109/7 fixant la méthodologie tarifaire pour le réseau de transport d'électricité et pour les réseaux d'électricité ayant une fonction de transport », launched on 9 February 2018.
The regulator proposes 1) a full exoneration from the network costs to new storage plants during 10 years; and 2) a 80%-exoneration for existing storage plants during five years provided that they undertake improvement works to increase their installed capacity and the size of their reservoir by 7.5%.

between Belgium and its neighboring countries. This first step of the study is the subject of a first deliverable, named 'Benchmark report on PHS profitability drivers in Western Europe'.

5. In a second step, the idealistic and theoretical assumptions that are necessary for a fair quantified comparison between countries in the first step are refined and focused, in order to give insights on the actual level of profitability of a Belgian PHS plant. This complementary step then enables to get a more realistic view on the profitability prospects of Belgian PHS. It is the subject of a second deliverable, named 'Note on the realistic assessment of profitability for the Coo-Trois Ponts PHS plant', and methodologically comes after the first step.

Step 1 - Comparative study of profitability drivers for pumped-hydroelectric storage in Western Europe

6. In the first step of the study, a focus is made on the estimation and comparison of profitability drivers of a PHS plant in several Western Europe countries. For each country, the benchmark identifies and looks to quantify the drivers which influence the profitability of PHS, in terms of costs and revenue streams. The results are used to study the correlation between Belgian PHS profitability and its national regulatory framework, and to assess the existence (or lack thereof) of a level playing field for PHS in the region.

Methodology

7. Profitability drivers of PHS storage are assessed for six European countries: Austria, Belgium, France, Germany, Great Britain and the Netherlands. Luxembourg, while in the scope of the benchmark, is not studied individually because the Luxembourgian PHS plant (Vianden) is connected to the German network of Amprion. Besides, the analysis of drivers for the Netherlands is limited to a qualitative analysis and a comparison of transmission costs and taxes with the other countries: as the Dutch potential for PHS is null, its inclusion in the main comparison of preferences from an investor point of view does not make sense.

8. The profitability drivers in each country are analyzed both qualitatively and quantitatively. With regard to revenue streams, the benchmark includes (i) revenues from the arbitrage on the day-ahead energy market (DA or day-ahead hereafter), (ii) revenues from the provision of ancillary services and (iii) revenues from capacity remuneration mechanisms (CRM). With regard to incurred costs, it includes (iv) transmission related costs such as tariffs or system management costs and (v) taxes and surcharges that the plant has to pay as a consumer or a producer of electricity. All other costs (personnel, maintenance, etc.) are considered equivalent. Therefore, they should not distort the profitability balance between countries and are not included in the benchmark.

9. The quantitative benchmark is based on simulations of a modeled PHS plant for the year 2017. An identical modeled plant is considered in each country, but which operates in different national settings in terms of tariffs, taxes, prices and volumes. The plant adjusts its decisions and arbitrages between the available revenue options to maximize its annual profit, following an economically rational strategy.

10. The main set of simulations models the behavior of PHS plants when they are able to participate to energy markets and CRMs only. This methodological choice to focus on these two revenue streams (keeping ancillary services for a theoretical sensitivity analysis) stems from the modeling constraints, which prevents from modeling the behavior on ancillary services with the same level of precision and comparability than on the day-ahead and on CRMs. Beside the exclusion of ancillary services, several simplified assumptions have to be taken to ensure a fair comparison

between countries and to cope with the lack of essential data which would have enabled a modeling as realistic as possible. Hence, effects such as imperfect foresight of prices or market resilience are not taken into account, and the results are therefore optimistic, constituting an upper boundary of the profitability outlook. It is nevertheless expected that these assumptions affect all compared plants with a similar order of magnitude, thus not distorting the validity of results. Therefore, the benchmark's results should be used to compare the relative levels of profitability between countries, but they do not enable to estimate the actual profitability that an actual plant might display (this is the objective of the study's second step).

Main results

11. The results highlight the variety of PHS profitability drivers and their impact in the studied countries. Among the most interesting findings in the qualitative benchmark, one should mention:

    a. Regarding transmission related costs, Germany and Austria both present specific tariff regimes for PHS but it translates differently: German PHS is supposed in the modeling to be eligible for a total 10-year exemption of network tariffs[4], while the specific tariffs in Austria are still significant and are completed by other charges related to network management.

    b. Regarding taxes and surcharges, all countries but Great Britain apply some to energy storage. In those countries, charges are particularly related to public service obligations for the power system and renewable subsidies. Exemptions regimes are in place for some taxes in Belgium, Germany and Austria, where PHS is considered as part of the consumption.

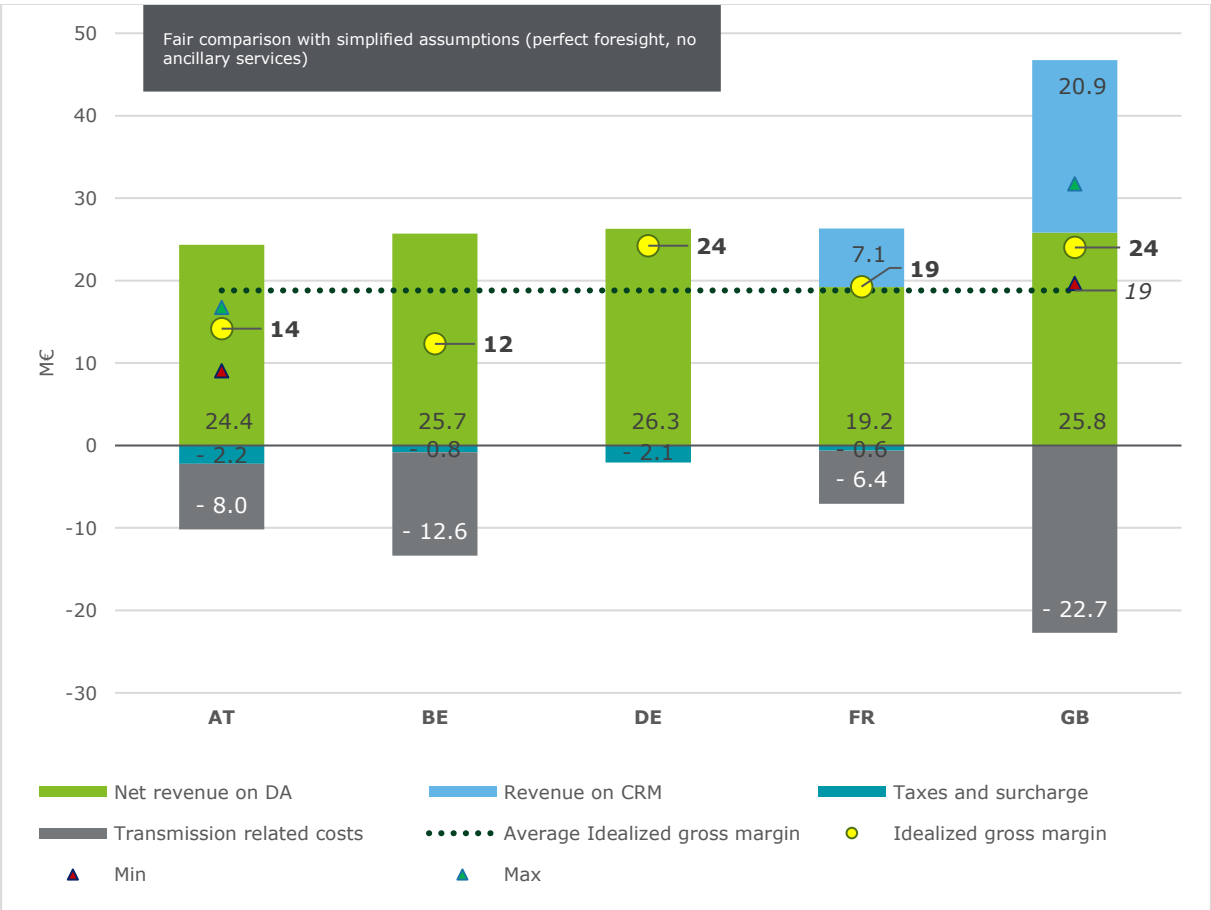
    c. Regarding remuneration conditions of PHS, only France and Great Britain have capacity remuneration mechanisms (capacity markets) which are suitable for PHS, as strategic reserves in Germany and Belgium would not be interesting for storage plants in operation. The gain in profitability thanks to these markets is very high.

12. Quantitatively, the results translate into differences in energy volumes, earned revenues, incurred costs and therefore gross margin levels from one country to another. The following figure presents the main outcomes of the simulations, assuming that PHS can participate to day-ahead markets and capacity remuneration mechanisms only. Note that the simulations do not compare directly the profitability levels; they present instead the idealized' gross margins[5] before operational and maintenance costs, which take into account everything that is different from one country to another (identical operational and maintenance costs are assumed for the purpose of a fair comparison). Furthermore, as already explained, it should be reminded that those results only illustrate the relative levels of profitability from one country to another for a theoretical plant; absolute estimations of actual PHS profitability in a given country, for a given plant, should not be extracted from these values.

[4] All storage built in Germany after 4 August 2011 benefits from a 20-year exemption. However, for the study's purpose one assumes for Germany a PHS plant built before 4 August 2011. Such a plant can also benefit from a 10-year exemption of network tariffs if its technical characteristics have been improved: size of reservoir should be increased by at least 5% or their turbine output should be increased by at least 7.5%. The exemption begins at the date of the expansion's commissioning. It is generally known that a large majority of old PHS in Germany have made these improvements to benefit from the exemption. Therefore, this is what one also assumes for the PHS German plant in the study.

[5] Gross margin before operational and management costs is calculated as the difference between all studied costs and revenue categories. It is idealized because it is the optimized margin that the PHS plant could get in the ideal setting of the modeling.

Figure 1. **Comparison of idealized gross margins earned by the modeled PHS plant – Simulations for year 2017 with participation to DA markets and CRMs**



Source : Deloitte – Economic Advisory

13. The quantitative results for participation to DA and CRM highlight that France, Germany and Great Britain are the most favorable countries for PHS with a gross margin around or higher than € 20 million. They place Belgium at the bottom of the profitability ladder.

    a. France, Germany and Great Britain benefit from specific advantages which enable them to retain the quasi entirety of their net revenue on the day-ahead. In France and Great Britain, revenue from capacity markets (respectively € 7 and 21 million) almost compensate the incurred costs and taxes. German PHS is meanwhile assumed to fulfill the conditions for tariff exemption[6], which helps it realize the best idealized gross margin in this simulation.

    b. Belgium does not benefit from a level playing field with these countries. Without ancillary services, PHS idealized gross margin is only € 12 million, twice as low as in Great Britain and Germany, and 30% lower than the average for the five countries. This comes despite a net margin on the day-ahead (€ 26 million) close to the average of analyzed countries. The profitability of Belgian PHS is instead impacted by very high transmission tariffs (€ 12 million), second only to Great Britain.

    c. A closer look to Austria shows that the tariffs in regions where PHS is actually located (Vorarlberg and Tyrol) are 6 €/MWh (withdrawn) lower than in the rest of Austria. In these regions, the total cost related to transmission tariffs is € 5 million and the idealized gross

[6] Conditions for PHS build before 4 August 2011 (see footnote 4)

margin reaches € 17 million (green triangle on the figure), which isolates even more Belgian PHS as the lowest idealized gross margin earner.

14. A closer look at transmission related costs highlights the strong divergences of regulatory frameworks from one country to another. They confirm the qualitative analysis of those frameworks. The tariff designs are especially critical for Belgian and British PHS, which incur transmission tariffs higher than € 10 million.

15. As explained in the methodology, the sensitivity analysis on quantification of revenue from ancillary services cannot be placed at the same level of accuracy than the main simulations on energy markets and CRMs, due to highly theoretical and extreme assumptions which distort the behavior in order to identify, rather than quantify, the main drivers. In other words, they should not be regarded with the same level of certainty and realism than the benchmark's main set of results, but they provide some very striking findings for each country. In particular, they show that even extremely optimistic assumptions as to the participation to frequency services do not enable Belgian PHS to compensate for its lag in profitability, especially with regard to France, Germany and Great Britain.

16. In conclusion, the results confirm that there is no level playing field between the studied countries. In particular, Belgian PHS appears to lag millions behind France, Germany and Great Britain, pulled down by relatively high transmission tariffs and not compensated by any revenue from capacity mechanisms. A tariff exemption as suggested by the CREG should tackle the concerns on the attractiveness of Belgian PHS and helps reach a level playing field with France, Germany and Great Britain.

17. Moreover, the results raise a second question regarding the financial viability of Belgian PHS: scientific intuition suggests that a more realistic simulation (imperfect foresight on the day-ahead, consideration of other operating and recurrent maintenance cost, no hydraulic bypass …) would have resulted in operating losses. The question of the actual economic conditions of Belgian PHS is the subject of the second step of the study, which seeks to approach the realistic situation of the Coo-Trois Ponts PHS plant.

Step 2 - Realistic assessment of the profitability of a Belgian PHS

18. In the second step, a focus is made on the actual profitability of Belgian PHS. Indeed, the idealistic and theoretical assumptions made in the first benchmark prevent any conclusion on the economic situation of an actual PHS plant. The specific case of a Belgian plant is now analyzed more accurately. Previous unrealistic and optimistic assumptions are now refined to consider as accurately as possible the reality of a Belgian PHS plant similar to that of Coo-Trois Ponts, in terms of technical and economic behavior as well as earned revenue. The simulations now consider all revenue streams and in particular those from ancillary services.

Methodology

19. The work entails refining the idealistic assumptions of the benchmark's theoretical framework, considering instead more accurate characteristics of the power plant and of the operator (e.g. impossibility to perform hydraulic bypass, imperfect foresight on prices or the participation to Electrabel's portfolio of ancillary services providers). The plant is now supposed to be able to adjust its behavior taking into account the possibility of revenue from the day-ahead energy market, CRMs and ancillary services.

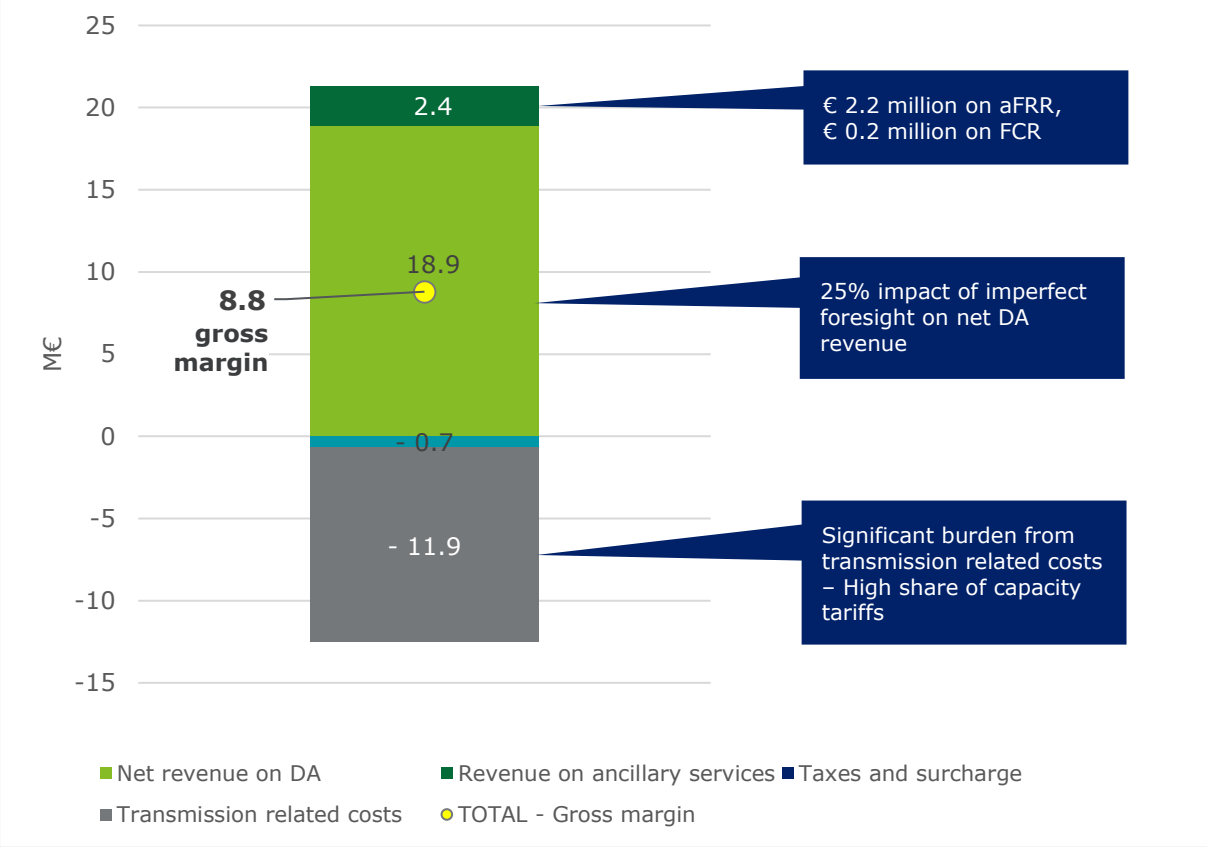
20. It should be noted that the work cannot reproduce exactly Coo-Trois Ponts's technical, economic and financial characteristics: this would have required more extensive modeling of an existing plant with a history of operational decisions and events, and many specific details to take into account. Therefore, the exercise remains theoretical but looks to get as close as possible to the reality of Coo-Trois Ponts, within a certain number of remaining simplifying modeling assumptions. In particular, the assumptions regarding the operation on the day-ahead market (e.g., the impact of bids on prices is only partly taken into account, the plant is fully available all year long) should still tend to overestimate the related revenue[7].

Main results

21. With this more realistic set of assumptions, the gross margin of the modeled Belgian plant is € 8.8 million, significantly lower than figures calculated previously, confirming the very optimistic and unrealistic assumptions previously made. The main source of revenue by far is the day-ahead market (€ 18.4 million), while provision of frequency reserves (FCR and aFRR) brings additional € 2.4 million, in line with the observations made by the team responsible for Coo. As identified in the first step, transmission related costs are a major profitability burden. They amount to € 11.9 million.

[7] Regarding ancillary services, several assumptions influence the outputs in opposite directions. For example, activation of frequency reserves is not considered for the sake of simplicity, and revenue from black start and voltage services is supposed equal to the opportunity costs. These assumptions seem reasonable and should affect only marginally the results, according to Electrabel's teams. In any case, the impact of ancillary services' assumptions on the results' validity should remain limited.

Figure 2. **Distribution of the gross margin with realistic assumptions approaching the conditions of Coo-Trois Ponts - Simulations for year 2017 with participation to DA market, frequency reserves provision and CRM**



Source : Deloitte – Economic Advisory

22. Ultimately, the gross margin appears to be insufficient to cover the remaining operational costs (personnel, insurances, market dispatching, daily follow-up and maintenance, …, estimated at € 10 million by Electrabel). Electrabel is then unable to perform lifetime extension works needed to keep on operating at full capacity (these works would amount to an additional € 5 million annually on average, according to Electrabel)[8].

23. In this critical context, the tariff exemption envisaged in Belgium by the CREG can be actually perceived as the answer to two policy objectives. The first objective is to ensure the operational sustainability of existing Belgian PHS, which requires a positive net operating result that is not currently verified. In this respect, the simulations show that a (unconditional, simultaneous and permanent) 50% exemption rate would enable to cover the aforementioned operating and recurrent maintenance costs needed to keep on operating the Coo-like plant at full capacity. The second objective, indeed highlighted in the consultation document, is to encourage investments, both for new projects and existing plants. But this second objective cannot be tackled without addressing the first, *i.e.* ensuring the financially viable operation of existing PHS in the country. Therefore, to reach the desired policy objectives regarding storage deployment and use, the eventual level of tariff exemption and the conditions for eligibility could be calibrated to both ensure the financial sustainability of existing PHS plants and to attract the targeted additional investment levels.

[8] Source: Electrabel internal analysis. The data was not crosschecked by Deloitte. Deloitte cannot be held accountable of any use of these costs and of the resulting estimations

Deloitte.

PARTENAIRE #FRANCE 2023

Commission de Régulation de l'Electricité et du Gaz (CREG)
A l'attention de Monsieur Laurent Jacquet, Directeur
Rue de l'Industrie 26-38
B-1040 BRUXELLES

PAR RECOMMANDE

Bruxelles, le 2 mars 2018

Notre réf. : CB/SF/LET/18-12

Contact **Téléphone** **e-mail**

Cher Monsieur Jacquet,

Veuillez trouver en annexe notre réponse au document de consultation publique 1718 portant sur le volet «Stockage».

Nous nous tenons à votre disposition pour toutes questions éventuelles.

Nous vous prions d'agréer, Cher Monsieur Jacquet, l'expression de nos salutations distinguées.

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