Design of a financing mechanism for the future hydrogen network in Luxembourg

Design options and parameters for an intertemporal cost allocation mechanism

Prepared for:

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1. Introduction

1.1 Policy and market context

Luxembourg published a **national hydrogen strategy** on 27 September 2021, setting the goal of converting current hydrogen consumption to renewable hydrogen by 2030. The Luxembourg government is currently working on updating this hydrogen strategy. Against the backdrop of likely significant import requirements to meet hydrogen demand in industrial and transport applications, as well as Luxembourg's future role as a transit country within a European hydrogen network, various coordination, planning, and financing requirements arise for both the construction of domestic pipelines and the connection to the European Hydrogen Backbone. In this context, the hydrogen strategy emphasizes the critical importance of (cross-border) hydrogen pipeline infrastructure and the necessity for extensive cooperation with EU member states and third countries.

In March 2025, the Luxembourg Parliament adopted a **legal framework for the planning and development of hydrogen transport infrastructure** domestically and with neighboring countries. Legislative procedure started before final requirements of the EU Hydrogen and Gas Decarbonisation Package was adopted, thus full transposition is still required and the *Loi du 31 mars 2025 relative à l'établissement de réseaux de transport d'hydrogène*[1] is setting a first legal basis for a hydrogen market in Luxembourg. Among other aspects, this framework defines the appointment of a hydrogen network operator by the minister, the classification of hydrogen projects as public interest (*utilité publique*), and long-term planning procedures, including a ten-year network development plan. In Article 2, the law also defines the process and evaluation criteria to assess applications to build and operate the future hydrogen network in Luxembourg. Creos Luxembourg Hydrogen S.A. (CLH), a subsidiary of Creos Luxembourg S.A. (CL), was designated by the minister as hydrogen network operator (HNO) on 1st of December 2025.

CLH plans to connect to the European hydrogen network as part of the "HY4Link" project (recently designated as a Project of Common Interest – PCI and included in the first ten-year network development plan subject to final investment decision by CLH) in two consecutive phases:

- In the **first phase (2027 – 2032)**, a pipeline from France will supply mainly the south of the country with hydrogen. This phase involves the construction of a hydrogen network connecting Frisange (LU) to the French networks of NaTran (formerly GRTgaz) and eventually to the mosaHYc network. This infrastructure would be the first hydrogen facility in southern Luxembourg with a distribution network supplying key potential industrial sites in Esch/Belval, Differdange, Bascharage, and Pétange. In the complementary information to its application, CLH maintains that it will operate phase 1 of the projects as a distribution network pursuant to EU Directive 2024/1788, given that it only includes one interconnector to France. This has implications for the level of unbundling required, e.g., it entails less strict requirements regarding the joint use of resources between CLH and its parent company.
- The **second phase (2032 – 2035)** adds an interconnection between Belgium and Luxembourg, establishing a transit network connected to the Belgian backbone via the Bras (BE) border point. The second phase with an additional connection to Belgium is envisaged to be operated under the

[1] Loi du 31 mars 2025 relative à l'établissement ... - Legilux

transmission network regime, whereby CLH aims to operate under the so-called ITO-model ("Independent Transmission Operator") as defined in Articles 63 to 67 of Directive 2024/1788, which is the legally preferred model for CLH as they are part of a vertically integrated undertaking with CLH / Creos being part of the Encevo Group.

According to CLH[2], the total investment costs, on Luxembourg territory, for the two project phases amount to up to ~ € 280 million. For phase 1, CLH estimates investments of € 89 million. For phase 2, required investments are projected at € 192 million. Both phases also include the installation of equipment required for the operation of the future network, such as metering, measurement, and control stations. A further domestic expansion of the first project may be realized in 2035 to connect additional demand centers. These further connections would add additional investment costs of € 22 million and increase the total CAPEX to ~ € 300 million.

This hydrogen network is planned to meet the future hydrogen demand of Luxembourg as well as possible future transit flows from other countries. These projections – for Luxembourg as for many other European countries - are inherently uncertain and are primarily defined in Luxembourg's National Energy and Climate Plan (NECP) as well as simulations conducted by CLH with the support of Guidehouse across three scenarios. Figure 2 provides an overview of these demand projections ranging from 5 to 10.7 TWh in 2050.

Figure 1: Project map showing the two phases of hydrogen network build out (Source: https://www.creos-net.lu/en/individuals/projects-innovation/hy4link)

[2] Initial estimations based on cost indicators from the German Kernnetz. Subject to change.

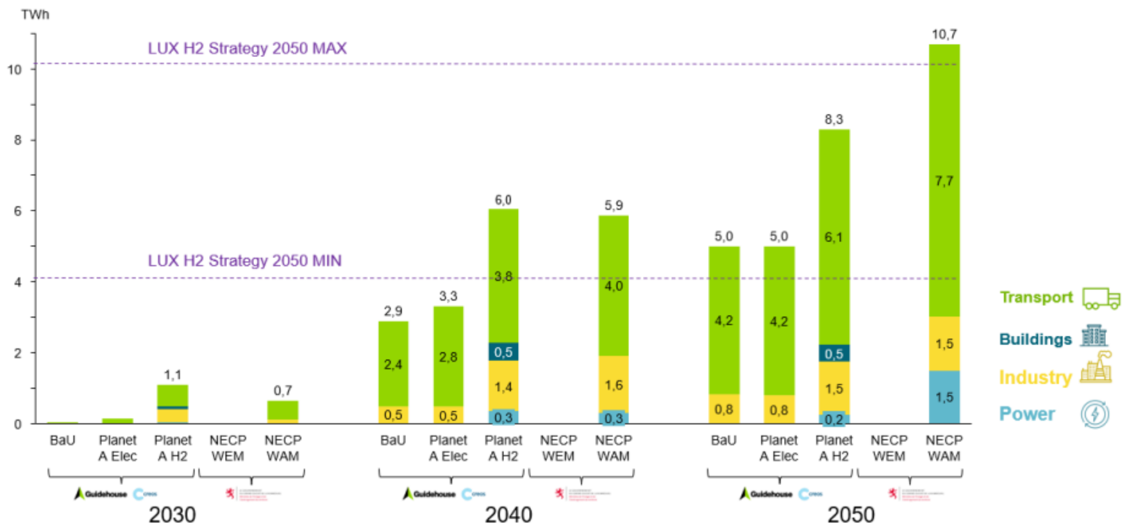

Figure 2. Projected hydrogen demand by sector and scenario. Source: CLH & Guidehouse (2024): Gas & Hydrogen Scenario Report.

Pursuant to Article 12 of Luxembourg's hydrogen transport network law, the determination of a tariff regulation for hydrogen networks will be carried out by the Luxembourg regulator *Institut Luxembourgeois de Régulation* (ILR) no later than one year before the anticipated commissioning of the first network. A key aspect of the regulatory framework to be defined is the future financing of hydrogen infrastructure. For this, effective instruments must be selected, designed, and legally implemented. The main challenge in this context is the high initial investment costs, which may result in potentially high network tariffs for only a small number of users – and limited hydrogen volumes - at the outset. Additionally, the amortization risk for network operators in the early phase could delay the development of the hydrogen infrastructure.

Finally, Luxembourg's potential role as a transit country gives rise to questions about cross-border cost allocation with neighbouring countries. Hence, a corresponding cost sharing mechanism may have to be negotiated between relevant countries and their corresponding network operators, defining how (and if at all) costs for the build-out of a cross-border network in Luxembourg that will also enable (substantial) transit flows from other countries are distributed across benefiting countries. For this paper, we assume that this cost sharing mechanism is not part of the national financing instrument in Luxembourg, and thus that the financing model, in principle, covers all hydrogen pipeline costs incurred by the HNO on the territory of Luxembourg. Moreover, and independent of a potential cost sharing mechanism with neighboring countries, we assume (working hypothesis) that transit volumes are subject to the same tariffs as flows occurring within Luxembourg, i.e., transit flows are subject to entry and exit tariffs at the border / interconnection points instead of production and offtake point. A decision on how and if transit tariffs contribute to costs arising in Luxembourg is important since it has implications for the scope and required support of the national de-risking / guarantee mechanism.

A final decision regarding the future financing and regulatory framework for hydrogen networks in Luxembourg has not yet been made and will be supported by this study. However, a new funding line was implemented by law on the 8th of December 2025 that permits CAPEX grants to be awarded to hydrogen infrastructure projects (up to €60 million per project)[3]. The focus of this paper, however, is to assess a combination of CAPEX grants with a model of intertemporal cost-allocation as the main instrument to support the build-out of hydrogen infrastructure in Luxembourg. Design recommendations for the intertemporal cost-allocation mechanism take the effects that a combination with CAPEX grants will have into account. To the extent applicable, we consider learnings from other Member States implementing or planning to implement similar financing schemes (e.g. Germany, Denmark, Austria, the Netherlands).

1.2 Aim and structure of this paper

The aim of this paper is to support the Luxembourg Ministry of the Economy in the design and configuration of a financing mechanism for Luxembourg's future hydrogen network.

The remainder of this paper is structured as follows: In section 2, we describe the chosen financing model (intertemporal cost allocation + upfront CAPEX support) for the build-out and operation of the future hydrogen infrastructure in Luxembourg and explain the rationale for this decision. In section 3, we recommend design options for the chosen financing model. This entails a description of key design elements and available design options in section 3.1. With the help of an excel tool developed in this assignment, we derive suitable model-based parameters (or ranges of parameters) for the recommended design in section 3.2. We conclude this paper in section 4 with a summary of key observations from the scenario analysis and an overview of recommended design options.

[3] Loi du 8 décembre 2025 ayant pour objet le reno... - Legilux

2. Description and rationale to implement intertemporal cost allocation (with additional upfront CAPEX support)

2.1 Standard way of cost-recovery via tariffs does not work for hydrogen infrastructure

Investments in gas network infrastructure are highly capital-intensive and face the challenge of having to recover costs over many years. In case of hydrogen transport infrastructure, this is made more complex by uncertain future hydrogen demand, which introduces a significant volume risk. The European Union's regulatory framework (EU gas market package) for gas and hydrogen infrastructure seeks to address this by setting regulated cost-reflective tariffs that allow for the recovery of regulated revenues, covering depreciation, capital costs, and operational expenses.

The standard methodologies for setting tariffs are typically based on a straight-line depreciation of network operator's regulated asset base (RAB), excluding potential upfront CAPEX support paid, without any cost shifting to the future. A standard cost-based tariff reflects actual investment and operational costs and the allowed revenue for grid operators, i.e., a regulated return on investment. This means that network investment costs are recovered over the economic lifetime of the network via tariffs set over a certain period (e.g. annually).

While this approach offers a straightforward framework and is commonly employed for gas networks, its application to hydrogen pipeline transportation or distribution can result in prohibitively high tariffs for hydrogen offtakers, especially early adopters. Compared to investments in the natural gas networks, the built out of hydrogen transmission networks presents unique challenges. These networks are planned to serve expected demand that still needs to build up over the coming decades. In the early years, the usage of the network will be too low to cover infrastructure costs at reasonable tariff levels. If the standard approach of straight-line depreciation was used, this would likely result in extremely high tariffs in the initial stages, making hydrogen transport via pipelines unaffordable for users. Such high tariffs could trigger a negative cycle of declining demand and rising costs, possibly stalling market development and leading to stranded hydrogen infrastructure assets. Furthermore, current market uncertainties make it difficult for users to commit to long-term capacity contracts, further complicating cost recovery. From the perspective of network operators, unpredictable demand growth bears a high risk that investment costs are not fully recovered.

To address these issues, it is necessary to implement mechanisms that lower tariffs during the initial phase of network development when demand is still building and at the same time ensure cost recovery for the network operator. To support the development of an internal hydrogen market, the EU has introduced Directive (EU) 2024/1788 (the Directive) and Regulation (EU) 2024/1789 (the Regulation). The Regulation provides the possibility to Member States to allow the recovery of network costs over time via an intertemporal cost allocation mechanism. It further specifies that Member States may complement these mechanisms with measures to cover the financial risks of hydrogen operators.

2.2 CAPEX support will reduce financial burden and risk for hydrogen network investments

Luxembourg will introduce a funding line that provides investment support for projects that support the ecologic and energy transition in Luxembourg. Under this funding line, investment support of up to €60 million can be granted per project. This threshold complies with the threshold defined in the General Block Exemption Regulation (GBER) for energy infrastructure, which declares certain categories of aid compatible with the internal market and exempts them from a formal state aid notification procedure with the European Commission.

Article 11 of the corresponding law foresees that investment support will be available for the construction of hydrogen infrastructure and further stipulates that support is only available for infrastructure that is used exclusively for hydrogen from renewable sources. Up to 100% of the "funding gap" is eligible for support. According to article 2 of the law, the funding gap is calculated as the difference between the revenues (also considering any other possible subsidies) and the economic costs – including investment and operating costs – of the subsidized project and those of an alternative investment project that the company would undertake without support (counterfactual scenario). In case of hydrogen infrastructure, it is reasonable to assume that no counterfactual scenario is required, since the alternative would be that no investment in hydrogen infrastructure occurs.

The foreseen investment support is a direct payment reducing the capital expenditure (CAPEX) required to realize the H2 infrastructure. De facto, the government assumes part of the costs. This reduces the network operator's risk of not recovering its costs and has a positive impact on the project's bankability and financing conditions. At the same time, it lowers the RAB of the network operator, since the investment support received is deducted from the CAPEX considered when calculating network tariffs. On the one hand, this lowers the network operator's revenues, on the other hand it lowers network tariffs for consumers, as the basis (RAB), i.e. the asset costs that need to be recovered via network tariffs, are smaller.

CLH plans to build Luxembourg's hydrogen network in two phases, each phase constituting a separate project. The total investment support could therefore amount to up to €120 million, which is a significant share of the projected CAPEX of the two projects. However, receiving the maximum amount of support may not be in a HNO's interest, as it would result in a significant reduction of the RAB and hence allowed regulated revenues. Notably, an option to pay back received investment support to the state at a later stage is not foreseen in the current regulatory framework. The HNO would benefit from the option to pay back investment support as this would increase the RAB and thereby allowed revenues, i.e. allowing the HNO to maximise revenues while shielding substantial parts of the investment risks. On the other hand, such a payback would result in an (ex-ante) increase in network tariffs for the consumers, which poses a risk to them.

Provided that the HNO applies for investment support, the risk of a delayed or failed market ramp-up is reduced, as parts of the costs are already covered and network tariffs are lowered. Nevertheless, there is a remaining risk that the regulated network tariffs are still prohibitively high during the initial ramp-up phase when trading volumes are low, potentially stifling market development before it gains momentum. Therefore, the foreseen investment support alone is not sufficient to guarantee marketable network tariffs. Consequently, the Luxembourg government intends to combine investment support with an instrument for intertemporal cost allocation, similar to the amortization account model implemented in Germany.

2.3 Intertemporal cost allocation ensures cost recovery and low ramp-up tariffs

The intertemporal cost allocation model is a financing mechanism designed to enable the private-sector development of the hydrogen network through network tariffs, with subsidiary state backing, by shifting costs to later points in time when they can be recovered by user tariffs. Fundamentally, the approach aims for the construction of the **hydrogen network to be financed privately via network tariffs**, analogous to gas and electricity networks. However, at the start of the ramp-up phase, when the number of network users is still small, the initially high investments cannot yet be fully passed on to network users, as the tariffs would be too high. For network operators, this results in an amortisation risk that inhibits private investment in hydrogen networks.

To address this issue, **network tariffs are capped** at a ramp-up tariff, which is below the tariff level required to cover the approved network costs, i.e. allowed revenues of the network operator, based on its CAPEX and OPEX. The difference between the allowed revenues and the low revenues generated from a small number of network users paying a capped ramp-up tariff, is covered by payments from a special intertemporal cost allocation account (“amortisation account”), which is provided with a bank loan. An institution managing the amortisation account compensates the network operators by paying out the difference between the approved network costs and the network tariff revenues. The managing institution should be set up as a legal entity that is separate from the network operator to ensure that the debt accumulated in the amortisation account does not appear in the balance sheet of the network operator.

In later years, when a higher number of network users are connected, actual revenues from the ramp-up tariff that then applies to a larger number of offtakers are envisaged to exceed the allowed revenues of the network operator leading to overrecovery and thus a gradual balancing of the amortisation account. The account is considered "balanced" when its cumulative value returns to zero. The balancing of the amortisation account shall be achieved by the pre-defined year of the closing of the account, at the latest. The long-term goal of the concept is that, from that year onwards, the ramp-up phase will be fully completed, and the network will be fully financed by customers and transit flows, analogous to today’s electricity and natural gas networks.

The **key challenge** in the intertemporal cost allocation model lies in **determining the capped network tariff**. On the one hand, the ramp-up tariff should be set as low as possible. On the other hand, the conditions stipulating that the amortization account must be balanced by the end of its duration should be duly considered. To set a ramp-up tariff that meets these criteria, an estimate of the relevant parameters that influence the financing of the hydrogen network must be made up until the end of the amortisation account duration. The relevant parameters are 1) the costs of constructing, maintaining and operating the hydrogen network and the WACC applied to the residual asset value, i.e. the basis of calculating the allowed revenues, 2) the ramp-up of connected customers, i.e. the revenues from network tariffs, 3) the network tariff system, i.e. the type of tariffs and 4) the interest rate of the loan that is used to cover the revenue gap in the amortisation account. If, for example, the costs of the hydrogen network are underestimated or the hydrogen ramp-up is overestimated, this will result in a ramp-up tariff that is too low to balance the amortisation account. In that case, the ramp-up tariff will subsequently need to be corrected upwards. Conversely, overestimating the costs or underestimating the hydrogen ramp-up will result in a tariff that is too high and may later be reduced.

Both cases illustrate the careful balance that needs to be struck when determining the ramp-up tariff. To accommodate for the likely event that the development – especially regarding the ramp-up of connected consumers – deviates from the projections, a **regular revision of the ramp-up tariff** is required. Such periodic revision and potentially adjustment of the tariff is intended to ensure the balancing of the amortisation account. An important condition here is that the level of network tariffs can only be adjusted to the extent that the ramp-up itself is not jeopardised. Although the tariff can be adjusted periodically, it should be chosen so that only minor or no future adjustments are necessary to increase planning and investment certainty for market participants and the HNOs.

Despite the possibility to revise the ramp-up tariff, a risk remains that the amortization account cannot be balanced by the end of its duration. This risk is covered by a **subsidiary state guarantee** for the settlement of the amortisation account, meaning that the state provides a compensation guarantee **to the bank that provides the loan for the amortisation account**. Any remaining loan balance at the end of the amortization account duration, which may be a result of a failed hydrogen market ramp-up, must be assumed by the state. This state guarantee also improves the bankability of the amortization account operator which, as a result, will benefit from lower interest rates. The future legal and regulatory framework may also require the network operator to pay a share of the compensation should the amortization account not be balanced at the end (i.e. **deductible** for network operators).

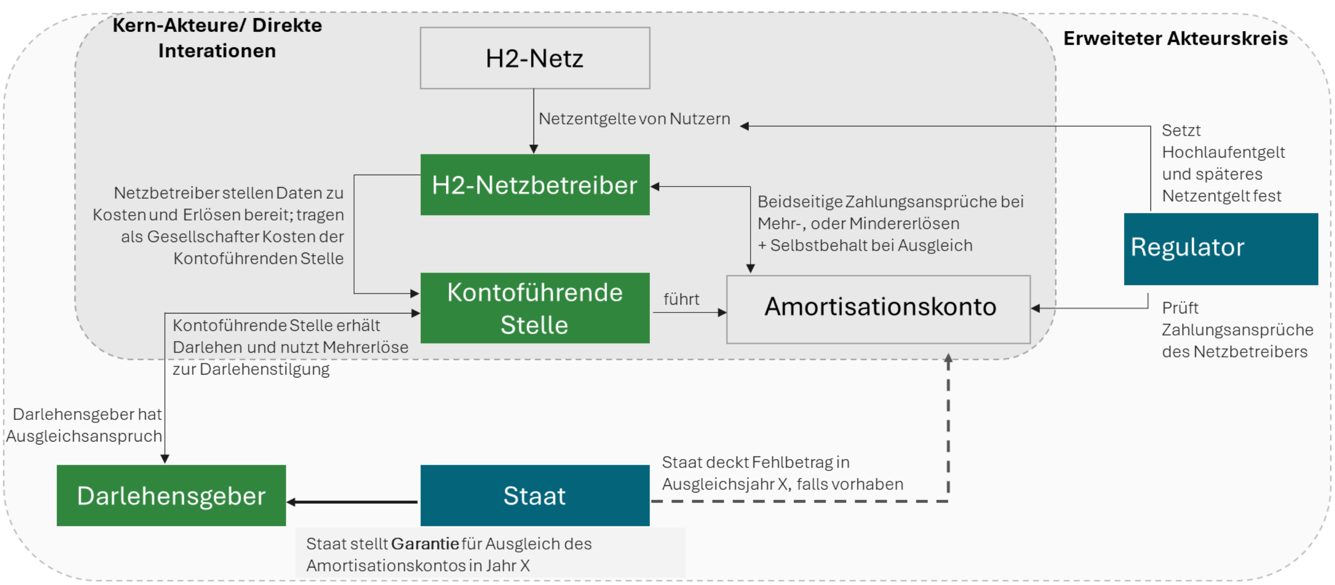

Figure 3: Illustration of institutional set-up and involved actors in intertemporal cost allocation mechanism (Source: Guidehouse)

2.4 Chosen financing model: Combination of CAPEX support and intertemporal cost allocation

Both instruments, the investment support and the intertemporal cost allocation complement each other and can be combined.

With the direct subsidies in form of the investment support the government assumes part of the CAPEX, which reduces the network operator's risk of not recovering its costs. The RAB is lowered by the extent of the investment support and is the basis for calculating the network operator's allowed revenues. Lower costs must be recovered, which also reduces required network tariffs and facilitates the hydrogen market ramp-up.

The intertemporal cost allocation can be a suitable addition to the investment support as it ensures that the annual revenues of the operators are sufficient to cover the remaining costs. In addition, the government assumes most risks associated with a delayed or failed market ramp-up (depending on the amount of the deductible). At the same time, it is guaranteed that the use of the networks will not be impeded by prohibitively high tariffs in the initial stages of the market ramp-up. Since the investment support lowers the RAB, lower costs must be recovered throughout the duration of the intertemporal cost allocation mechanism, which reduces initial deficits on the amortization account. The investment support therefore also lowers the risk that the amortization account is not balanced at the end.

The following chapter expands on the design details of an intertemporal cost allocation mechanism for the build-out of a hydrogen infrastructure in Luxembourg and derives recommendations based on model-based calculations taking various hydrogen demand scenarios into account. The results are based on the financing model described in this section, which combines investment support with an intertemporal cost allocation mechanism. No additional operating support to lower network costs or tariffs is assumed.

3. Design aspects and parameterization for the chosen financing model

In the following section, we first describe and discuss relevant design elements, including potential design options, for the implementation of an intertemporal cost allocation mechanism for H2 infrastructure in Luxembourg (section 3.1). We then describe our excel tool and summarize key model results under different demand scenarios and other sensitivities (section 3.2) before providing a recommendation for the design and parameterization of the financing mechanism in Luxembourg (section 4).

3.1 Description of design elements and their options

3.1.1 Cap on grid tariffs (ramp-up tariff)

Description and discussion

The standard method for setting network tariffs is based on straight-line depreciation of the regulated asset base over a pre-defined duration, with costs recovered annually over the asset's lifetime (see section 2). While this approach is effective and widely used for gas networks, it poses challenges for hydrogen networks, as low initial demand would result in excessively high tariffs for early users. This could hinder market development, reduce infrastructure utilization, and create risks of unrecovered costs or stranded assets. Therefore, relying solely on traditional tariff methodologies may make hydrogen transport unaffordable at the start, placing an unfair burden on early adopters and discouraging long-term commitments from network users.

To address these challenges, a cap on grid tariffs paid by network users in the initial stages would support affordability for users and facilitate the ramp-up of hydrogen demand. The revenue shortfall resulting from lower initial tariffs could then be recouped via intertemporal cost allocation at a later stage, once higher demand volumes and broader network usage are achieved. As such, the capped tariff is at the core of the intertemporal cost allocation mechanism as it introduces a specific transitional tariff structure, the "ramp-up tariff" or capped tariff, which deviates from the standard cost-based tariff. The capped tariff is applicable during the designated payback period (see section 3.1.3) and is intended to gradually recover the full investment costs over time. In line with a recent ACER recommendation[4] and pursuant to Regulation (EU) 2024/1789 this capped tariff forming part of the overall tariff regulation must be approved by the national regulatory authority once the intertemporal cost allocation methodology is determined and implemented nationally. In the context of Luxembourg, the responsible regulatory authority is ILR.

The capped tariff can also be indexed to inflation using an adequate index such as the national consumer price index (CPI) to account for future price increases that would erode the value of the applicable capped grid tariff over time. This indexation may apply to all or only a subset of relevant costs that are part of the RAB, e.g., only OPEX that are subject to inflation instead of the full RAB.

[4] Recommendation No 02/2025

As outlined in section 2, any mismatch between actual revenue based on capped tariffs and the approved network costs is recorded into an intertemporal cost allocation account. The costs accumulating in the account can be recovered in the future, when the hydrogen offtake is higher.

For this paper and the model calculations described in section 3.2, we assume a range of parameters regarding tariff setting methodology and tariff design, which are however subject to a further definition by ILR. We describe these assumptions below.

General tariff setting methodology: ILR will define the tariff setting methodology. While the details of this methodology are not yet defined, a range of assumptions will be made for the purpose of this report:

- ILR defines the general tariff setting methodology and the methodology for determining the RAB. Based on that methodology, the HNO determines the RAB that needs to be recovered over the economic lifetime of the network (via intertemporal cost allocation mechanism).
- ILR determines a **depreciation method**. A straight-line depreciation over 35 years is assumed as a working hypothesis, i.e., investment that needs to be recovered annually decreases at a constant rate over time due to depreciation. Straight-line depreciations provide a fixed value for depreciation to be recovered through the tariffs. Alternatively, backloaded or other progressive depreciation methods could be implemented to allocate more depreciation to the later periods with larger expected utilisation, acting in themselves as kind of an intertemporal cost allocation mechanism[5].
- The HNO determines **eligible costs** on the basis of the general tariff setting methodology and the intertemporal cost allocation methodology. The capital expenses for network build-out are part of the eligible costs that fall under the intertemporal cost allocation mechanism. Direct subsidies to capital expenditures (CAPEX support outlined in section 2) are deducted from the RAB decreasing the network operator's allowed revenues. Allowed revenue related to the network's operating costs, both fixed and volume dependent, are determined on an annual basis taking into account actual flows through the network (i.e., not spread over time like CAPEX)
- ILR assumes a **return on investments** by defining a weighted average cost of capital (WACC) for operators which may be adjusted over time to account for changing market situations. The level of the remuneration should reflect the real risk borne by the HNO. This risk needs to be assessed considering the guarantees provided by the state and a potential risk-sharing mechanism, in particular the deductible (see section 3.1.2). If the operators are not exposed to the risk arising from an unbalanced debt account, no additional remuneration should be granted. In line with the recommendations provided by ACER, the capital asset pricing model (CAPM) can be used to set a WACC.

Principles for the design of tariffs and capacity products: The design of tariffs and capacity products will be determined by ILR based on the final legal framework implementing the Gases Directive (EU) 2024/1788 and the Gases Regulation (EU) 2024/1789. For the purposes of this report, we assume firm tariffs for annual entry and exit capacity to the hydrogen network that are non-distance related

[5] The application of backloaded depreciation could theoretically decrease the need for further interventions, however. They amplify the effects of demand risk and less flexibility, which may lead to liquidity gaps for operators and should therefore be carefully selected and possibly supplemented with fitting risk-mitigation mechanisms. Other depreciation methods that result in accelerated and larger depreciation values during the early periods of the network's lifetime lead to a larger need for an intertemporal cross-subsidisation.

and with no differentiation between transit and domestic flows. Tariffs are calculated for annual capacity bookings in €/kWh/h/a[6] and apply exclusively to non-interruptible capacity. This form of capacity booking is already used in the current gas market and expected to be implemented in other hydrogen markets (e.g. Germany). The tariffs are set on a non-distance related basis. More specifically, we make the following assumptions:

- No interruptible capacity product[7] is provided (at least initially), i.e., firm (uninterruptable) capacity is the only capacity product.
- Each year, the HNO forecasts the sum of entry and exit capacities, including transit volumes, and divides the approved total network costs for the system by these capacities. The result of this determines the level of the non-capped tariff that would apply in the absence of an intertemporal cost allocation mechanism.

Design aspects

Two main design aspects should be considered when setting a capped tariff:

Principles for setting the value of the capped tariff

- The goal of the intertemporal cost allocation mechanism is to provide affordable tariffs to the end users during the ramp up phase. Hence, the network users' willingness-to-pay (WTP) should be taken into account. However, WTP is inherently hard to estimate, partly because it almost certainly differs by type of end user (e.g. users in the transport sector subject to quotas, industry offtakers and power generators), and since grid fees typically only make up a smaller fraction of gas / hydrogen costs. Hence, the main benefit is to avoid excessive tariffs. Comparing the price of hydrogen against its (fossil-based) alternatives is a useful starting point, nonetheless, and can provide a (lower-end) indication on suitable levels. At the same time, while WTP may be a good initial benchmark, this does not automatically imply that it should be set as the capped tariff.
- Importantly, the capped tariff should be set at a level that increases the likelihood of balancing out the amortization account within the set payback period. In other words, the capped tariff level should provide for a realistic chance that ideally no financing gap remains in the end that would have to be covered by the state (and partly by operators in case of a risk sharing mechanism – see section 3.1.2).
- We provide indications on a suitable bandwidth for setting the capped tariff in section 3.2.4, taking these aspects into account, with a particular focus on tariff levels required to balance out the amortization account given projected hydrogen uptake.

Indexation of the capped tariff to inflation

- Luxembourg may implement inflation-indexed capped tariffs to protect against eroding of the real value of the capped tariff over time due to inflation (In our model calculations, we assume 2% on all costs.)

[6] The unit EUR/kWh/h/a is used in the gas market to price capacity bookings, representing the cost (€) to reserve a specific hourly transmission capacity (kWh/h) for an entire year (a). This allows grid operators to charge for the infrastructure availability (\(kWh/h\)) separately from the actual volume of gas consumed (\(kWh\)).
[7] Interruptible capacity is a type of product that cannot always be guaranteed and is usually sold at a discounted price compared to firm capacity. Pricing typically reflects the chance of interruption, relevant data, or is based on offering capacity opposite to expected flow directions

- Example: Germany indexes ramp up tariff to consumer price index.

3.1.2 Risk sharing mechanism (deductible for grid operators & opt-out option for state)

Description and discussion

Hedging network operators from all volume risks connected to their network planning while guaranteeing regulated revenues on all of their hydrogen-related investments may lead to a moral hazard issue, i.e., operators may not have the right incentives to make prudent investment decisions based on realistic demand projections (e.g., not overbuilding). Therefore, the allocation of reasonable risks to network operators to increase incentive compatibility for network planning and operation is a possibility. On the other hand, the effect on risks and thus financing costs of allocating more risks to hydrogen network operators should be duly considered to avoid unproportionally increasing investment costs for the build out of the hydrogen network, with implications for the costs that need to be recovered via grid tariffs in the end.

Hence, the intertemporal cost allocation mechanism could be complemented by a risk sharing mechanism between the state and hydrogen network operators. The implementation of this risk sharing mechanism refers to a situation where initial demand and/or cost expectations turn out to be too optimistic and demand lags significantly behind or costs are substantially higher, leading to a risk that the capped tariffs (see previous section) will not be high enough to fully recover the costs until the end of the duration of the intertemporal cost allocation mechanism (see next section). If the accumulated deficit is not balanced by the end of the duration of the intertemporal cost allocation mechanism, a (smaller) share of the remaining deficit will have to be covered by the hydrogen network operator(s) as a deductible with the remainder covered by the state.

An additional element could be an opt-out option for the state before the regular end of the intertemporal cost allocation mechanism. If it becomes evident that market development will not be sufficient to cover costs through the capped ramp-up tariffs within the initially planned duration, the state could be granted the option to terminate the intertemporal cost allocation scheme by an agreed point in time and assume all accumulated losses on the amortization account. In that case, the network will still be operated and the costs will not cease. However, the state could introduce other mechanisms to address the cost gap that do not entail a further accumulation of interest costs, such as direct annual compensation payments by the state. In case a deductible is defined for the opt-out option, the network operator is obliged to cover part of the shortfall at the time of termination of the mechanism. If it cannot pay the deductible, the assets will be transferred to the state for a price corresponding to the net residual value.

In case deductibles are considered necessary for the mechanism, it should be noted that the risks related to a failed market uptake of hydrogen are largely determined by an adequate regulatory and policy framework and thus subject to political decisions outside the direct control of network operators. Hence, when setting a deductible, transferring inherently unproductive risks beyond what is needed to ensure efficient investment signals for the build out of the network should be avoided. Therefore, a robust network planning process that ensures a demand-based network build out is a crucial component to avoid risks related to an inefficiently planned network (e.g., too large given projected demand). It can thus be considered as a foundation for an effective risk sharing between the state and network operators.

An additional element to lower the risk of overbuilding, which Luxembourg is considering, is to engage consumers via binding long-term capacity bookings in an open-season procedure. Making binding commitments under an open-season procedure involves consumers or shippers submitting irrevocable bids to secure firm capacity in new pipeline infrastructure. These legally binding bids, often part of a two-stage process, obligate participants to enter into long-term transportation service agreements, covering costs and justifying investment for network operators. Obliging consumers to make commitments of e.g. 10% of their forecast could enable the network operator to make more reliable forecasts of the entire demand. Chances of conducting a successful open-season procedure are higher for project phase 2, as price- and overall market developments will be easier to predict for potential offtakers than for phase 1.

Design aspects

The initial design choice relates to whether a risk sharing mechanism should be implemented in the first place (i.e., a deductible for network operators) or not. For example, Germany has implemented such a mechanism in the form of a deductible for network operators in case the amortization account is not balanced by 2055 (or before in case of an opt-out by the state – see below). We recommend the implementation of a risk sharing mechanism to ensure rational economic decisions by the HNO. However, its concrete design should be considered against the background of the HNO's limited influence on the overall market uptake of hydrogen. In this context, two main design aspects should be considered in addition:

- Size of the deductible for network operators:
    - Example: Germany with a deductible of 16%-24% by the end of the mechanism
    - *Hypothesis*: Below 20%. Lower level compared to Germany, since Luxembourg is considering to spread/lower the risk associated with the network build-out through other means, i.a. an open-season procedure for phase 2 in which consumers/shippers make binding capacity booking commitments.
- Opt-out option for state or without opt-up option for state
    - Example: Germany has introduced the option to terminate the intertemporal cost allocation mechanism by opt-up as of 2038 (with assumption of deficit by the state and deductible for operators between 16% and 24% depending on point in time of the cancellation).
    - *Hypothesis:* Implement opt-out option for the state already at a relatively early stage, i.e. 2040 or earlier, to ensure that the state can react early to costs getting so high that cost recovery under the intertemporal cost allocation mechanism is no realistic perspective. The state should have the option to opt-out each year as of the first year in which an opt-out can be made.

3.1.3 Duration of intertemporal cost allocation (payback period)

Description and discussion

The duration of the intertemporal cost allocation mechanism, which is the period over which the costs of the network will be recovered, is a key design element determining the expected demand over which the costs will be distributed. It also impacts directly the estimated tariff level, e.g., if the duration is set too short, this would increase the likelihood of remaining deficits on the amortization account at the end of its period in case of lower-than-expected demand and/or tariff levels are too low.

The duration of the mechanism can be seen as the latest date until which the amortization account is either balanced, or remaining deficits need to be recovered by the state and grid operators depending on the chosen risk sharing scheme (see section 3.1.2). As outlined in section 2, the account is considered balanced when its cumulative value equals zero. Hence, the account will also be considered balanced if the repayment of the financing provided occurs earlier than the amortization account's maximum duration.

The mechanism's duration can be set by the number of years its ramp up tariff(s) apply. In this context, taking the economic lifetime of the assets under consideration, here the depreciation of the future hydrogen pipeline network in Luxembourg over its economic lifetime, is a good basis. In any case, a duration that is longer than the assets' technical lifetimes should be avoided taking into account potential network (re)investments. Moreover, additional aspects should be considered when setting the mechanism's duration, such as the stability of ramp-up tariffs over time (i.e., avoiding constant adjustments to ensure balancing of the amortization account), maintaining an affordable level of ramp-up tariffs while ensuring a recovery of the initial deficits until the mechanism's end date.

The intertemporal cost allocation methodology can incorporate flexibility to modify the duration should there be substantial deviations from initial cost and demand assumptions. As outlined above, the estimation of network demand over time is crucial for setting adequate parameters for the intertemporal cost allocation mechanism. Development of demand, both in terms of profile and volume, impacts the distribution of costs over time and the tariff level, and strong deviations between initial and future demand imply that more costs need to be allocated to the future. Hence, the mechanism's duration may be adjusted in line with a changing demand evolution over time. For example, lower than initially planned demand would increase the account's deficit due to lower revenues if tariff levels are kept constant, which increases the period to recover full costs. In a context where demand does not evolve as planned, or actual costs prove to be higher than expected, an extension of the mechanism's duration could be considered to maintain ramp up tariff levels at an affordable level.

Design aspects

- Number of years of intertemporal cost allocation mechanism
    - Example: Germany and Denmark both foresee a duration of 30 years.
    - Working hypothesis for this report is a duration of 30 years for the intertemporal cost allocation mechanism
- Flexibility to adjust duration (upwards), or not
    - Examples: While Germany has not implemented the option to extend the duration, Denmark does foresee the flexibility to extend the period in case of additional or re-investments prolonging the lifetime of assets.
    - *Hypothesis:* Beyond automatic termination if amortization account is balanced, upward flexibility should be granted to account for potential delays in the build-out of phase 2, or in case of additional or re-investments prolonging the lifetime of assets (see Danish case). However, the duration should not be extended automatically in such case but remain up to the discretion of the state.

3.1.4 *Frequency of review of the mechanism and its assumption*

Description and discussion

Intertemporal cost allocation relies on inherently uncertain forecasts of costs and demand. To ensure tariffs are accurate and all costs can be recovered in the future, it is advisable to regularly review key assumptions, including network usage trends. In particular, a capped ramp-up tariff will be based on the initial design assumptions at its introduction to ensure full recovery of the intertemporal cost allocation, if inflation-adjusted and costs and demand development does not deviate (substantially) from these projections over time.

Both the Danish and German models include regular reassessment of the mechanism to ensure cost recovery over time and provide a cost-reflective tariff for users. In Denmark, DUR is expected to undertake annually or biannually reassessments of the assumptions and will calculate the necessary state subsidy on a yearly basis. In Germany, BNetzA will every three years reassess the level of the ramp-up tariff to ensure cost-reflectivity and the balancing of the intertemporal cost allocation account at the predefined time while ensuring tariff affordability for the users that may maximize demand.

Design aspects and options

A regular review schedule (e.g., every 2-3 years) for the H2 infrastructure financing mechanism in Luxembourg can be considered a no-regret option and is thus advisable. The review schedule could be aligned with the Ten-Year Network Development Plan (TYNDP), which is updated every two years.

3.2 Model-based parameterization of the chosen financing model

The quantitative analyses in the following sub-chapters address the question of how the financing of the hydrogen network can be achieved under different scenarios. Successful financing in this context means that the intertemporal cost allocation account will be balanced by or before the final year of its duration. To conduct the necessary calculations, we developed an excel-based tool, which is presented in the following section.

3.2.1 *Model description and objectives*

The Excel model is divided in 3 parts:

- The *Dashboard* (orange) is giving an overview of the main outputs and allows to choose a scenario and change major inputs.
- The green tabs are calculation sheets, where the main financial modelling is conducted.
- The Input (blue) is split into scenario definition, general input and specific input provided by CLH.

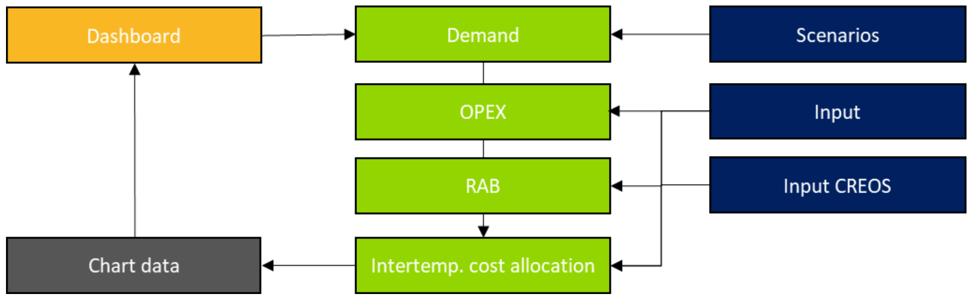

Figure 4: Model description and interdependencies

Dashboard (orange)

The *Dashboard* includes the main in- and outputs of the model. The hydrogen demand scenario can be chosen here and key parameters like max. national demand and max. transit volumes can be overwritten, if the user wants to implement changes. The main output is a chart highlighting the amortisation account balance for the defined tariffs. Additionally, detailed assumptions can be changed like CAPEX funding or the regulated return on equity.

For one selected tariff, detailed charts can be extracted:

- The capped ramp-up tariff in comparison to the cost-reflective tariff over time
- The allowed revenue compared to the capped ramp-up revenue over time
- The amortisation account balance over time

Calculation (green)

First, in the *Demand* sheet, the projected pipeline capacity booking is calculated based on the projected hydrogen demand. Therefore, the hydrogen demand and respective capacity needs are linearly interpolated between the given reference years for all scenarios. Based on the chosen scenario in the Dashboard, the demand ramp-up for further calculations is set.

The *OPEX* sheet takes the provided input from CLH and calculates total operational expenditures for general operation, pipeline operation, and other expenditures (e.g., ENNOH). CLH provided input until 2037, afterwards steady costs of operation are assumed incl. an annual inflation rate.

In a next step, the *Regulated Asset Base (RAB)* is calculated. Here, capital expenditures for phase 1 and 2 are taken from the provided input. The total capital costs (incl. interest during construction) are depreciated over a defined lifetime. The resulting Regulated Asset Value (RAV) is used to calculate the regulated return on capital. Finally, the annual allowed revenue is the sum of return on capital, RAB depreciation and OPEX. A cost-reflective tariff is estimated by dividing the annual allowed revenue with expected capacity needs from the *Demand* sheet.

The *intertemporal cost allocation* is calculating the balance of the amortisation account. The allowed revenue is subtracted from a capped ramp-up revenue, which is derived from a defined capped ramp-up tariff multiplied with the scenario capacity. The difference is booked on an amortisation account, including an interest rate. This calculation is done for six pre-defined tariffs.

Input (blue)

In the *Scenarios* sheet, the defined hydrogen demand scenarios (see Chapter 3.2.3) are implemented and transferred into respective needed pipeline capacities. If some scenario parameters are overwritten in the *Dashboard*, the values are adjusted accordingly. The *Input* sheet contains general model input, which is not changed in the different scenarios. The *Input HNO* includes CAPEX and OPEX assumptions provided by the designated HNO.

Model limitations

The chosen fixed tariff is constant over time and increases with inflation. The model therefore cannot show the implications of an adjusted tariff, if the regulator sees the necessity to adjust during the ramp-up. The hydrogen ramp-up between the reference years is assumed to be linear, while in reality a more unsteady increase is expected.

CAPEX funding is included as a one-time upfront payment for each of the 2 project phases. A funding provided over several years, which has cash-flow implications for the HNO, cannot be shown.

The provided CAPEX assumptions from the HNO are not linked to hydrogen volumes. However, operational costs are expected to slightly change depending on hydrogen flows, which is currently not implemented in the model.

The end year of the amortisation account can be set in the Dashboard. However, the calculation in this model is limited until 2065, as it is expected that the amortisation account as this is considered the longest timeframe accepted by the Luxembourg government to determine if the ramp-up will have succeeded or failed.

3.2.2 Key model assumptions

Parameter	Value	Source/Assumption
Duration of intertemporal cost-allocation mechanism	30 years	Ramp-up expected to be either successful or failed after this time
Capped ramp-up tariffs for Entry and Exit	10, 15, 20, 25, 30, 35 €/kWh/h/a	Transit tariffs are assumed to be the same as local Entry and Exit tariffs
Capacity factor[8]		GH assumptions based on industry expertise
National offtake	0,8	Full load hours of hydrogen offtake compared to max. booked.

[8] A capacity factor is the ratio of what a facility/asset actually produces over a given period compared to what it could have produced if it had operated at full capacity the entire time. In this case the capacity factor refers to the industry's offtake compared to the maximum offtake capacity.

		Explanation: Industrial offtakers usually run complex processes that cannot be operated flexibly, so their offtake is very constant.
Transit	1	Assuming steady transit at full capacity
Infrastructure costs		Provided by HNO
Phase 1	88.600.000 €	HNO: Pipeline connection to France (2027-2032), while 2027-29 just low costs for studies and engineering (~2 M€ per year)
Phase 2	192.000.000 €	HNO: Transit connection to Belgium (evenly distributed between 2032-35)
Further connections	22.000.000 €	Eventual further connections
Investment support		
Phase 1	30.000.000 €	CAPEX support in line with national funding regime
Phase 2	60.0000.000€	CAPEX support from national funding and/or CEF-E (Additional CAPEX funding via CEF-E possible as project has PCI status. Currently CEF-E is mainly supporting feasibility and FEED studies, rather than construction costs.)
OPEX	annual increase by 2% (inflation)	Operational costs were provided by HNO until 2037 incl. general OPEX, operational costs, and costs for ENNOH
Amortisation account		
Interest rate estimate on loan (with state-backed guarantee)	4 %	4% interest rate of KfW loan is the level assumed for calculations for the German amortisation account
WACC	risk reflective rate: 5 to 7%	Must reflect the market and corporate risk for HNO as well as elevated risk for hydrogen infrastructure investments in comparison to WACC for power grids in Luxembourg.

		When related to German amortisation account, particularities of Luxembourg hydrogen market have to be reflected with additional risk premium. In practice, periodic adjustments will be made to account for short-term changes in the financial market.
Deductible	below 20 %	Lower compared to German amortisation account (24%)
Depreciation		
Pipeline	35 years	Straight-line depreciation over the economic lifetime
Other assets	20 years	Straight-line depreciation over the technical lifetime

3.2.3 Scenarios to model sensitivities

The viability of the intertemporal cost allocation mechanism is highly dependent on the speed and scale at which the hydrogen economy ramps up. Income is generated from network tariffs, which are borne by network users. If the ramp-up of the hydrogen economy is slow, revenues will be low, causing the difference between costs and income to result in a larger balance on the amortization account. Conversely, high network tariffs will lead to a slow market ramp-up, which in turn further reduces revenues.

Estimating the development of the network demand over time is the key part of the parametrization of an intertemporal cost allocation mechanism. Therefore, we model sensitivities of the intertemporal cost allocation mechanism primarily on the parameter of development of demand. The way demand changes over time affects how costs are distributed and what the tariff will be. If demand is much lower at the start compared to later years, a larger portion of costs must be deferred to the future. Additionally, how quickly demand increases also impacts the cost allocation over time. The length of the cost allocation mechanism may also be determined based on projected demand trends.

The following table presents the set of scenarios used in the model to reflect different market ramp up pathways that are within the range of projections of national demand defined in Luxembourg's National Energy and Climate Plan (NECP) as well as simulations conducted by the HNO with the support of Guidehouse across three scenarios (see section 1.1). The scenarios in Table 1 are not sector-specific demand projections, but scenarios for overall national demand of molecular hydrogen (excluding hydrogen-based fuels) and transit. Figures for transit flows transported from and to other countries via the future network in Luxembourg are uncertain and depend mostly on developments outside of Luxembourg's control. They are assumed to range between 1,5 TWh in 2050 in the *"Low H2 ramp up"* scenario up to 3 TWh in 2050 in the *"High H2 ramp up"* scenario.

In **all scenarios** listed in Table 1, domestic hydrogen offtake from the pipeline starts when the infrastructure of the first project phase of HY4Link is commissioned in 2032. Additional transit flows are assumed to start with the commissioning of the second project phase in 2035 in the scenarios 1), 3) and 5). In all scenarios, the hydrogen offtake and transit flows grow until 2050, when they reach their maximum. This maximum level is also assumed for all years after 2050.

In scenarios 1), 2), 3), and 5), instead of a linear ramp-up of hydrogen offtake (or transit) from 2032 (or 2035) to 2050, a faster ramp-up until 2040 is assumed. This is based on the expectation that the years up to 2040 will be crucial for the success of the hydrogen ramp-up and for achieving national and European targets, and that there will be corresponding political support measures. According to this assumption of an accelerated ramp-up in the early years, these scenarios reach 65% of the maximum hydrogen offtake/transit projected for 2050 already by 2040. This corresponds to a steep linear increase from 2032/2035 to 2040, followed by a less steep linear increase from 2040 to 2050.

In contrast, scenarios 4) and 6) assume a consistent linear increase from 2032/2035 to 2050.

Table 1: Scenarios for hydrogen ramp up and transit flows used to model effects (figures in TWh)

Scenario	2032 (domestic)	2050 (domestic)	2035 (transit)	2050 (transit)	**2040 total (linear)**	**2040 total (65% progress)**	**2050 total**
1) Medium H2 ramp up ("Base scenario")	1	4,5	0,5	2,5		**4,55**	**7**
*2) **Low** H2 ramp up*	0,6	2,5	0	1,5		**2,6**	**4**
*3) **High** H2 ramp up*	1	7	1	3		**6,5**	**10**
*4) **Delayed** H2 ramp up*	0,1	4,5	0	2,5	**2,89**		**7**
*5) **No CAPEX support** medium H2 ramp up*	1	4,5	0,5	2,5		**4,55**	**7**
*6) **Worst-case**: delayed low H2 ramp up + 50% higher CAPEX*	0,1	2,5	0	1,5	**1,67**		**4**

The aim of the first scenario, the *Medium H2 ramp up* (***Base scenario***), is to initially depict a case where the ramp up of hydrogen demand – and thus the utilization of the hydrogen network – is medium, i.e. lying in the middle of demand projections made in the NECP. It reaches a maximum of 7 TWh in 2050. It reflects an overall functioning ramp-up of the hydrogen economy, which is consistent with Luxembourg's energy and climate policy. The following scenarios can be seen as variations of the *Base scenario*.

In the ***Low H2 ramp up*** scenario, national demand and transit flows have a lower start in 2032/2035 and only reach a maximum of 4 TWh in 2050. By contrast, a particularly high level of hydrogen demand is assumed in the ***High H2 ramp up*** scenario, reaching 10 TWh in 2050.

In the ***Delayed H2 ramp up*** scenario, the same level of demand is reached in 2050 as in the *Base scenario*, however, the demand is much lower at the start and picks up in the later years. The ***No CAPEX support*** scenario assumes the same speed and level of H2 ramp up as the *Base scenario*, the only difference being that no investment support is made use of by the HNO. As the level of investment support that will be applied for is unknown, this scenario is chosen to illustrate the impact that up-front investment support has on the intertemporal cost allocation mechanism. The scenario, however, does not account for potentially less favourable financing conditions in case no CAPEX support is applied for.

The ***Worst-case*** scenario combines three negative developments for the H2 ramp up. In this scenario, the H2 ramp up is delayed and only reaches the low levels of the *Low H2 ramp up* scenario. In addition, the CAPEX are 50% higher compared to what is assumed in the other five scenarios. Each of these adverse developments has a certain probability of occurrence that should not be underestimated. The scenario does not describe a complete failure of the ramp up, but a ramp up that faces numerous obstacles and that will not result in the clearance of the intertemporal cost allocation account via the capped tariffs.

3.2.4 Scenario analysis

In this section, we illustrate results for the different hydrogen ramp up scenarios. In each scenario, we illustrate for different ramp up tariff levels the development of the amortisation account balance over time, the maximum account balance and the year in which the account is cleared. For easier comparison between the scenarios, the effects of a network tariff of 20 EUR/kWh/h/a[9] (equivalent to 9,5 ct/kg_{H2}[10]) are taken as an example.

[9] The unit EUR/kWh/h/a is used in the gas market to price capacity bookings, representing the cost (€) to reserve a specific hourly transmission capacity (kWh/h) for an entire year (a). This allows network operators to charge for the infrastructure availability separately from the actual volume of gas consumed.
[10] Assuming 0,8 capacity factor: (20 EUR/kWh/h/a) / (8760 h/a * 0,8) * 33,3 kWh/ kg_{H2} = 9,5 ct/kg_{H2}
Consumers will have to bear the costs of exit capacity network tariff directly, but ultimately the entry capacity network tariff will also be passed on to the final customer price. Hence, the costs of transportation per kg, that the final customer will bear are, is 19 ct/kg for a network tariff of 20 EUR/kWh/h/a.

Scenario 1): Medium H2 ramp up scenario ("Base scenario")

In the *Base scenario*, total network utilization (demand and transit) starts with moderate levels of 1 TWh (domestic demand in 2032) and 0,5 TWh (transit in 2035), grows quickly to 4,55 TWh in 2040 and reaches 7 TWh in 2050.

The key results of the calculations are shown in Figure 5 below. In the *Base scenario*, a network tariff of 20 €/kWh/h/a clears the account in 2046. With that tariff, the maximum account balance reaches €64,94 million in year 2040. From this year onwards, the revenues from network tariffs exceed the allowed revenues of the operator and can be used to start balancing the account.

The minimum network tariff shown, that would suffice to clear the account is 15 €/kWh/h/a, which would occur in 2054. With that tariff the account balance reaches its peak of ~ €126 million in 2044.

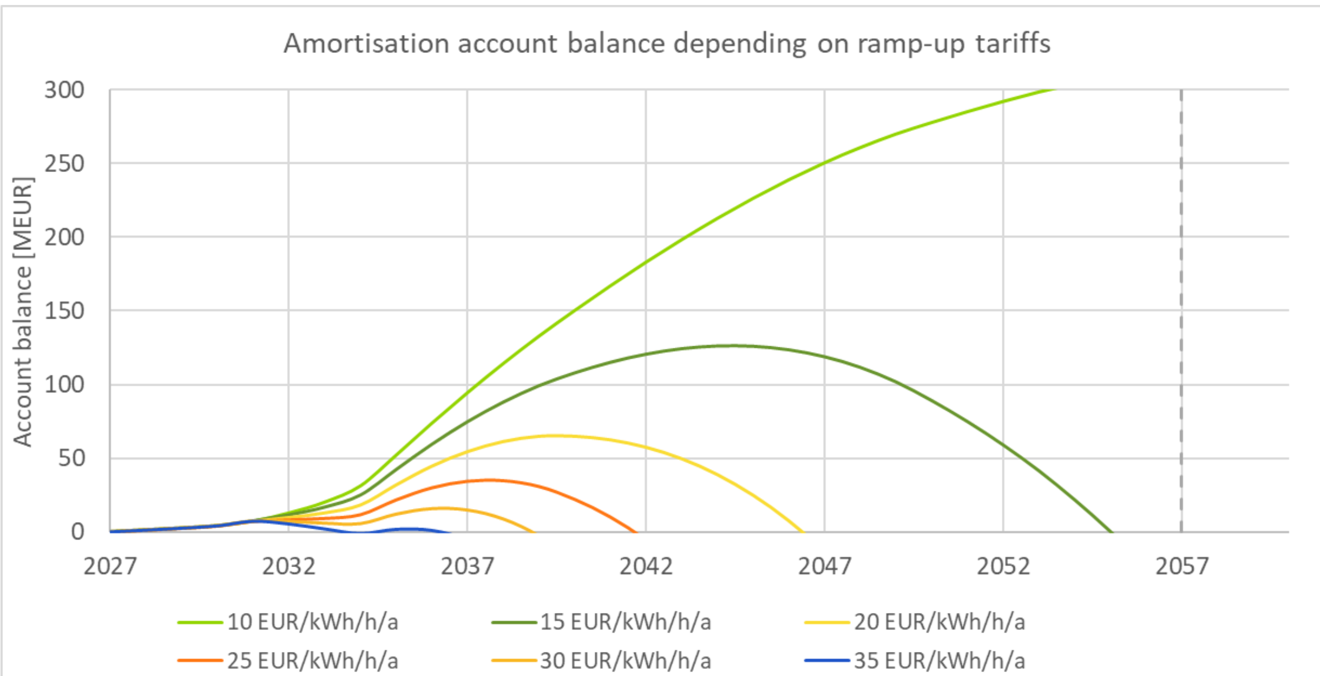

Figure 5: Different network tariff levels in the *Base scenario*.

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	326,46 MEUR	2057	post 2057	63,52 MEUR
15,0 EUR/kWh/h/a	125,91 MEUR	2044	2054	0,00 MEUR
20,0 EUR/kWh/h/a	**64,94 MEUR**	**2040**	**2046**	**0,00 MEUR**
25,0 EUR/kWh/h/a	34,93 MEUR	2038	2041	0,00 MEUR
30,0 EUR/kWh/h/a	15,53 MEUR	2036	2038	0,00 MEUR
35,0 EUR/kWh/h/a	7,24 MEUR	2031	2036	0,00 MEUR

Table 2: Overview of the results of the amortization account in the *Base scenario*

In the following sections, parameters – mostly related to the development of hydrogen demand – are varied in comparison to the *Base scenario*. The main focus of the analyses is the impact of these parameter changes on the year of clearance of the account and its maximum balance.

Scenario 2): Low H2 ramp up scenario

In the *Low H2 ramp up scenario*, total network utilization (demand and transit) starts with low levels of 0,6 TWh (domestic demand in 2032) and 0 TWh (transit in 2035), grows to a total of 2,6 TWh in 2040 and only reaches a maximum of 4 TWh in 2050. All other assumptions remain unchanged compared to the *Base scenario*.

The key results of the calculations are shown in Figure 6 below. In the *Low H2 ramp up scenario*, a network tariff of 20 €/kWh/h/a does not lead to the clearance of the account before the end of its duration. With that tariff, the maximum account balance reaches ~ €238million in year 2053. From this year onwards, the revenues from network tariffs exceed the allowed revenues of the operator and can be used to start balancing the account. However, due to the non-clearance by 2057, a deductible of ~ €46 million will have to be borne by the operator (assuming a deductible of 20%).

The minimum network tariff shown, that would suffice to clear the account is 30 €/kWh/h/a, which would occur in 2051. With that tariff the account balance reaches its peak at ~ €104 million in 2042.

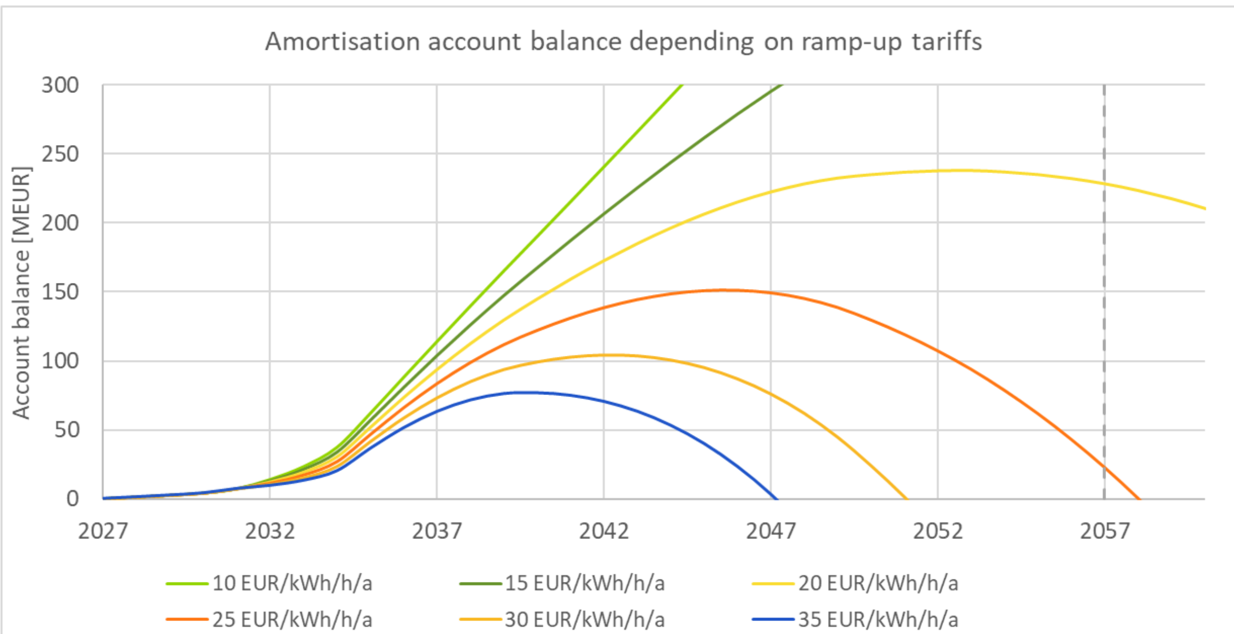

Figure 6: Different network tariff levels in the *Low H2 ramp-up scenario*

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	1687,07 MEUR	post 2057	post 2057	233,46 MEUR
15,0 EUR/kWh/h/a	1358,64 MEUR	post 2057	post 2057	198,69 MEUR
20,0 EUR/kWh/h/a	**1030,21 MEUR**	post 2057	**post 2057**	**163,91 MEUR**
25,0 EUR/kWh/h/a	701,79 MEUR	post 2057	post 2057	129,14 MEUR
30,0 EUR/kWh/h/a	478,97 MEUR	2054	post 2057	94,36 MEUR
35,0 EUR/kWh/h/a	390,56 MEUR	2049	post 2057	59,58 MEUR

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	899,66 MEUR	2057	post 2057	127,89 MEUR
15,0 EUR/kWh/h/a	527,85 MEUR	2057	post 2057	86,77 MEUR
20,0 EUR/kWh/h/a	**237,87 MEUR**	**2053**	**post 2057**	**45,66 MEUR**
25,0 EUR/kWh/h/a	151,05 MEUR	2046	post 2057	4,54 MEUR
30,0 EUR/kWh/h/a	104,40 MEUR	2042	2051	0,00 MEUR
35,0 EUR/kWh/h/a	76,57 MEUR	2040	2047	0,00 MEUR

Table 3: Overview of the results of the amortization account in the *Low H2 ramp-up scenario*

Scenario 3): High H2 ramp up scenario

In the *High H2 ramp up scenario*, total network utilization (demand and transit) starts with levels of 1 TWh (domestic demand in 2032) and 1 TWh (transit in 2035), grows to a total of 6,5 TWh in 2040 and reaches a maximum of 10 TWh in 2050. All other assumptions remain unchanged compared to the *Base scenario*.

The key results of the calculations are shown in Figure 7 below. In the *High H2 ramp up scenario*, a network tariff of 20 €/kWh/h/a clears the account in 2039. With that tariff, the maximum account balance reaches ~ €24 million in year 2037. From this year onwards, the revenues from network tariffs exceed the allowed revenues of the operator and can be used to start balancing the account.

The minimum network tariff shown, that would suffice to clear the account is 10 €/kWh/h/a, which would occur in 2056. With that tariff the account balance reaches its peak at ~ €140 million in 2045.

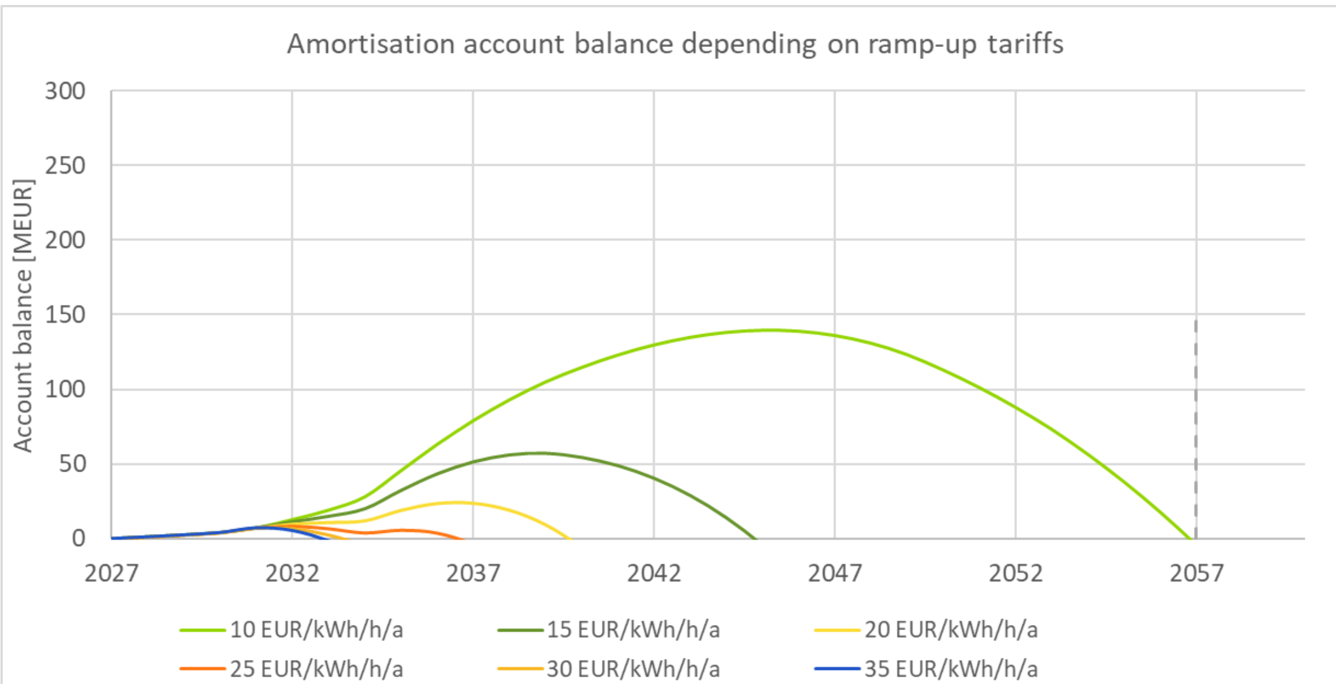

Figure 7: Different network tariff levels in the *High H2 ramp-up scenario*

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	139,76 MEUR	2045	2056	0,00 MEUR
15,0 EUR/kWh/h/a	57,22 MEUR	2039	2044	0,00 MEUR
20,0 EUR/kWh/h/a	**23,77 MEUR**	**2037**	**2039**	**0,00 MEUR**
25,0 EUR/kWh/h/a	8,33 MEUR	2032	2036	0,00 MEUR
30,0 EUR/kWh/h/a	7,24 MEUR	2031	2033	0,00 MEUR
35,0 EUR/kWh/h/a	7,24 MEUR	2031	2032	0,00 MEUR

Table 4: Overview of the results of the amortization account in the *High H2 ramp-up scenario*

Scenario 4): Delayed H2 ramp up

In the *Delayed H2 ramp up scenario*, the network utilization reaches the same maximum level of 7 TWh as in the *Baseline scenario*. However, the utilization levels are much lower in the initial stages. The total network utilization starts with 0,1 TWh (domestic demand in 2032) and 0 TWh (transit in 2035), grows to 2,89 TWh in 2040 and reaches a maximum of 7 TWh in 2050. All other assumptions remain unchanged compared to the *Base scenario*.

The key results of the calculations are shown in Figure 8 below. In the *Delayed H2 ramp up scenario*, a network tariff of 20 €/kWh/h/a clears the account in 2052 (12 years later than in the *Baseline scenario*). With that tariff, the maximum account balance reaches ~ €174 million (€109 million higher than in the *Baseline scenario*) in year 2044. From this year onwards, the revenues from network tariffs exceed the allowed revenues of the operator and can be used to start balancing the account. All network tariffs lower than 20 €/kWh/h/a illustrated below do not suffice to balance the account. Compared to the *Baseline scenario*, the delay increases the minimum required network tariff by about 5€/kWh/h/a.

It becomes apparent that the effects of a delayed hydrogen ramp-up on the financing of the hydrogen core network are very significant. Most importantly, the prolonged period of low network utilisation considerably increases the balance in the account.

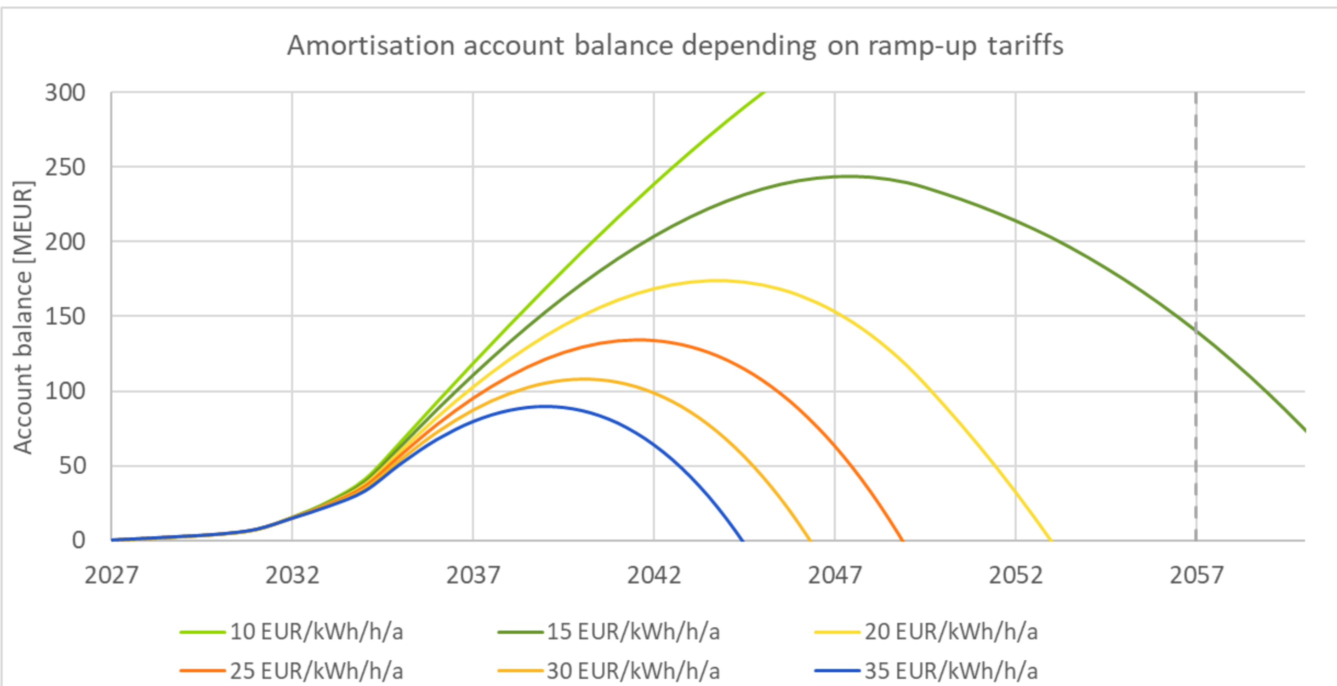

Figure 8: Different network tariff levels in the *Delayed H2 ramp-up scenario*

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	494,81 MEUR	2057	post 2057	88,74 MEUR
15,0 EUR/kWh/h/a	243,75 MEUR	2047	post 2057	28,04 MEUR
20,0 EUR/kWh/h/a	**174,09 MEUR**	**2044**	**2052**	**0,00 MEUR**
25,0 EUR/kWh/h/a	133,75 MEUR	2042	2048	0,00 MEUR
30,0 EUR/kWh/h/a	108,01 MEUR	2040	2046	0,00 MEUR
35,0 EUR/kWh/h/a	89,48 MEUR	2039	2044	0,00 MEUR

Table 5: Overview of the results of the amortization account in the *Delayed H2 ramp-up scenario*

Scenario 5): No CAPEX support medium H2 ramp up

In the *No CAPEX support medium ramp up scenario*, the network utilization is the same as in the Baseline scenario. The only difference is that no investment support is made use of by the HNO, which effectively increases the RAB by €90 million.

The key results of the calculations are shown in Figure 9 below. In the *No CAPEX support scenario*, a network tariff of 20 €/kWh/h/a clears the account in 2051 (5 years later compared to *Baseline scenario*). With that tariff, the maximum account balance reaches ~ €125 million (€60 million compared to *Baseline scenario*) in year 2043. From this year onwards, the revenues from network tariffs exceed the allowed revenues of the operator and can be used to start balancing the account. All network tariffs below 20 €/kWh/h/a illustrated below do not suffice to balance the account.

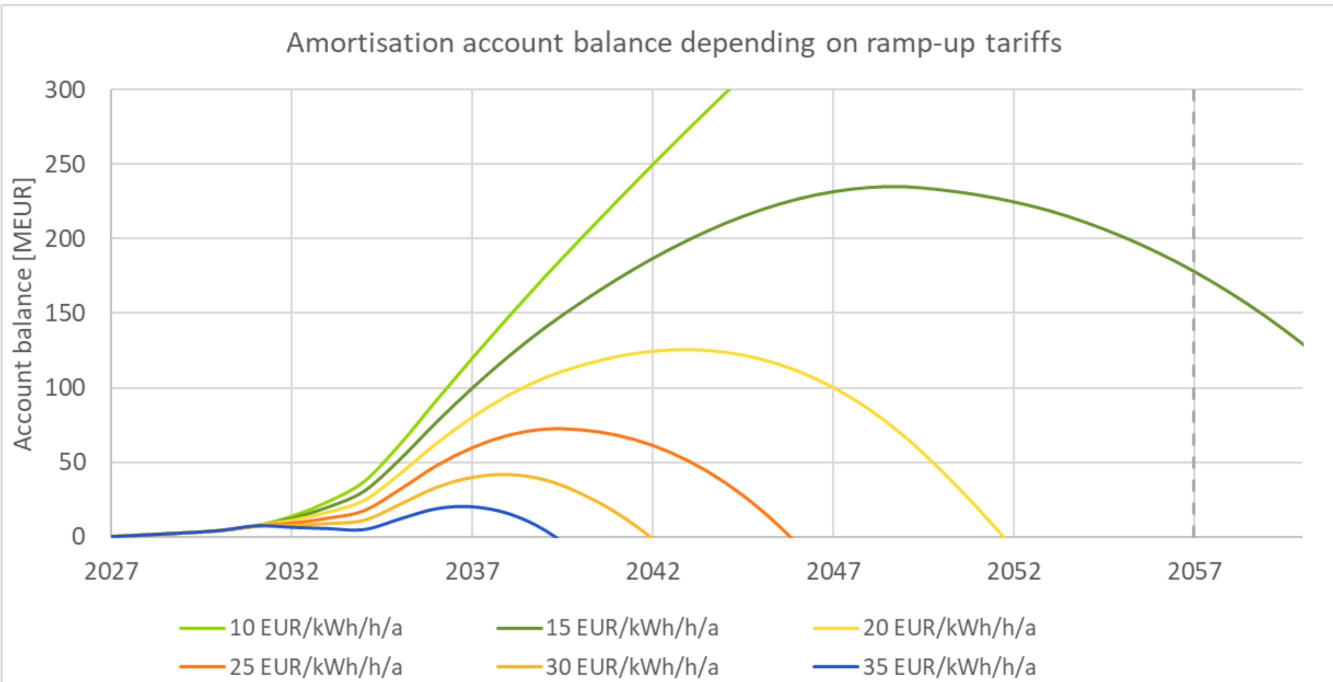

Figure 9: Different network tariff levels in the *No CAPEX support scenario*

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	667,56 MEUR	2057	post 2057	108,98 MEUR
15,0 EUR/kWh/h/a	235,28 MEUR	2049	post 2057	35,67 MEUR
20,0 EUR/kWh/h/a	**125,31 MEUR**	**2043**	**2051**	**0,00 MEUR**
25,0 EUR/kWh/h/a	72,38 MEUR	2039	2045	0,00 MEUR
30,0 EUR/kWh/h/a	41,85 MEUR	2038	2041	0,00 MEUR
35,0 EUR/kWh/h/a	20,04 MEUR	2037	2039	0,00 MEUR

Table 6: Overview of the results of the amortization account in the *No CAPEX support scenario*

Scenario 6): Worst-case scenario (delayed low H2 ramp up + 50% higher CAPEX)

In the *Worst-case scenario*, the CAPEX are 50% higher compared to what is assumed in the other five scenarios. In addition, the H2 ramp up is delayed and only reaches the low levels of the *Low H2 ramp up* scenario. The total network utilization starts with 0,1 TWh (domestic demand in 2032) and 0 TWh (transit in 2035), grows to 1,67 TWh in 2040 and reaches a maximum of 4 TWh in 2050. All other assumptions remain unchanged compared to the *Base scenario*.

The key results of the calculations are shown in Figure 10 below. In the *Worst-case scenario*, none of the network tariffs illustrated lead to a clearance of the account and the maximum account balances are very significant. With a network tariff of 20 €/kWh/h/a, in 2057, when the account is cleared by the state, the account balance is ~ €1030 million, of which the network operator covers ~ €206 million (deductible).

The effects of the adverse developments assumed in the *Worst-case scenario* are extreme. If such a development becomes apparent, early termination of the amortisation account by the state is a realistic option to avoid excessive costs.

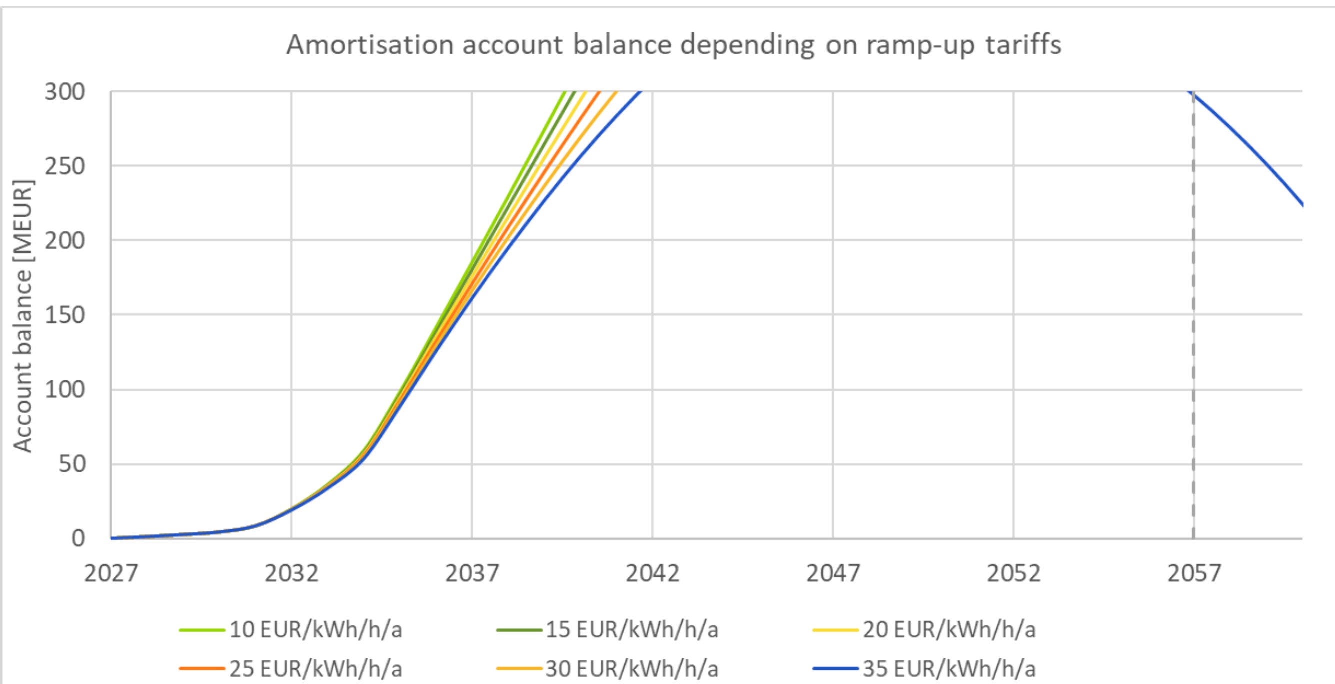

Figure 10: Different network tariff levels in the *Worst-case scenario*

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	1687,07 MEUR	2057	post 2057	233,46 MEUR
15,0 EUR/kWh/h/a	1358,64 MEUR	2057	post 2057	198,69 MEUR
20,0 EUR/kWh/h/a	**1030,21 MEUR**	**2057**	**post 2057**	**163,91 MEUR**
25,0 EUR/kWh/h/a	701,79 MEUR	2057	post 2057	129,14 MEUR
30,0 EUR/kWh/h/a	478,97 MEUR	2054	post 2057	94,36 MEUR
35,0 EUR/kWh/h/a	390,56 MEUR	2049	post 2057	59,58 MEUR

Table 7: Overview of the results of the amortization account in the *Worst-case scenario*

Sensitivities: effects of depreciation period

The excel-tool can be used to calculate the effects of changing parameters also within each scenario, for example the duration of the depreciation, which is determined by ILR. Working hypothesis for the calculations illustrated above is a straight-line depreciation of the pipeline infrastructure over a period of 35 years. However, the depreciation period for the RAB hydrogen network infrastructure could also be set at other levels, e.g. at 30 years (as in the Netherlands) or 40 years (as discussed in Austria). The shorter the depreciation period, the higher the annual allowed revenues and thus the larger the gap between allowed revenues and the revenues generated via the ramp-up tariff, which increases the account balance.

Taking the *Base scenario* and a ramp-up tariff of 20 EUR/kWh/h/a as example, a depreciation period of 30 years leads to a maximum account balance of €73 million in year 2040, with the account being balanced in 2047 (Table 8). A depreciation period of 35 years, results in a maximum account balance of €65 million in year 2040, with the account being balanced in 2046 (Table 9). Extending the depreciation period to 40 years, results in a maximum account balance of €60 million in year 2039, with the account being balanced in 2045 (Table 10).

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	354,39 MEUR	2057	post 2057	68,44 MEUR
15,0 EUR/kWh/h/a	139,37 MEUR	2045	2056	0,00 MEUR
20,0 EUR/kWh/h/a	**73,10 MEUR**	**2040**	**2047**	**0,00 MEUR**
25,0 EUR/kWh/h/a	40,77 MEUR	2038	2042	0,00 MEUR
30,0 EUR/kWh/h/a	19,20 MEUR	2037	2039	0,00 MEUR
35,0 EUR/kWh/h/a	7,24 MEUR	2031	2036	0,00 MEUR

Table 8: Results of *Base scenario* with depreciation duration of 30 years

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	326,46 MEUR	2057	post 2057	63,52 MEUR

15,0 EUR/kWh/h/a	125,91 MEUR	2044	2054	0,00 MEUR
20,0 EUR/kWh/h/a	**64,94 MEUR**	**2040**	**2046**	**0,00 MEUR**
25,0 EUR/kWh/h/a	34,93 MEUR	2038	2041	0,00 MEUR
30,0 EUR/kWh/h/a	15,53 MEUR	2036	2038	0,00 MEUR
35,0 EUR/kWh/h/a	7,24 MEUR	2031	2036	0,00 MEUR

Table 9: Results of *Base scenario* with depreciation duration of 35 years

Level of capped ramp-up tariff	max. account balance	year of max. account balance	year of clearance	Deductible
10,0 EUR/kWh/h/a	305,68 MEUR	2057	post 2057	59,82 MEUR
15,0 EUR/kWh/h/a	116,46 MEUR	2044	2054	0,00 MEUR
20,0 EUR/kWh/h/a	**59,68 MEUR**	**2039**	**2045**	**0,00 MEUR**
25,0 EUR/kWh/h/a	31,05 MEUR	2037	2041	0,00 MEUR
30,0 EUR/kWh/h/a	12,94 MEUR	2036	2038	0,00 MEUR
35,0 EUR/kWh/h/a	7,24 MEUR	2031	2035	0,00 MEUR

Table 10: Results of *Base scenario* with depreciation duration of 40 years

4. Summary of key observations from scenario analysis and overview of recommended design options

4.1 Key observations from scenario analysis

The scenario analysis shows that the speed and success of hydrogen ramp-up are critical for manageable financing. Lower hydrogen volumes or delays in hydrogen uptake lead to a longer period of low network utilization, which considerably increases the balance in the amortization account. Therefore, the overall success of the hydrogen ramp-up must be regarded as a key factor for the sound financing of the network. In addition, higher investment costs or absence of up-front investment support significantly raise the balance in the amortization account and the ramp-up tariff required to balance the account before the end of its duration.

If the ramp-up of hydrogen demand is successful, as illustrated by all scenarios except for the *Low H2 ramp-up scenario* and the *Worst-case scenario*, the overall situation for financing the network becomes manageable. For example, keeping the maximum account balance to a level below €150 million (taken for illustrative purposes) and balancing the account before its termination in 2057, can be achieved with a ramp-up tariff of 20 EUR/kWh/h/a in most scenarios. In the *Delayed H2 ramp up scenario*, a ramp-up tariff level of at least 25 EUR/kWh/h/a is required to keep the maximum account balance below €150 million. The *Low H2 ramp up scenario* requires a level of at least 30 EUR/kWh/h/a to stay below the maximum account balance below €150 million and balance the account before 2057.

In the *Worst-case scenario*, the financing situation deteriorates significantly, illustrating the big impact of a delayed and low H2 ramp up, but even more so of a significant increase in construction costs. The balance in the account reaches much higher levels for all ramp-up tariffs and only keeps rising until 2057 for all ramp-up tariffs below 30 EUR/kWh/h/a. In this scenario, additional direct or indirect subsidies for the network will be required throughout, or at least for most of, the ramp-up tariff phase.

Each of the adverse developments comprised in the Worst-case scenario has a certain probability of occurrence that should not be underestimated. The scenario does not describe a complete failure of the ramp up, but a ramp up that faces numerous obstacles. A ramp-up tariff much higher than those illustrated above would be needed to balance the account. This scenario demonstrates the need for the state to have the option to terminate the mechanism at an early stage (opt-out) to avoid excessive costs. Against this background, we recommend that the state should have the possibility to terminate the mechanism as of 2040 or even earlier, as long-term trends in the hydrogen ramp-up will already be apparent at that time. Alternatively (or in addition), the state may be granted the option to terminate the mechanism if the account balance hits a certain threshold and expectations are that a balancing of the account by/before 2057 is unrealistic.

The key challenge in the intertemporal cost allocation mechanism lies in determining the ramp-up tariff. On the one hand, the ramp-up tariff should be set as low as possible. On the other hand, the conditions stipulating that the amortization account must be balanced by the end of its duration should be duly considered. Setting the ramp-up tariff so that it is as low as possible but still enables balancing in 2057, results in higher additional costs due to the interest effect. Therefore, we recommend setting a ramp-up tariff that would result in the balancing of the account before 2057. Setting a higher ramp-up tariff from the beginning would also help to reduce the compound interest effect. Considering the scenario calculations, **we recommend setting a ramp-up tariff of at least 20**

EUR/kWh/h/a or 25 EUR/kWh/h/a. In addition, a regular review of the ramp-up tariff is advised to account for developments in the hydrogen ramp up and the account balance.

4.2 Overview of recommended design and parameterisation of financing model

Design elements & options	Recommended design choice	Rationale
Cap on grid tariff ("ramp-up tariff")	Implement an initial ramp-up tariff of at least 20-25€/kWh/h/a	For most scenarios, a tariff of 20€/kWh/h/a balances the account before its termination in 2057 and limits max. account balance to a level below €150 million. A tariff of 25€/kWh/h/a lowers overall costs due to lower (compound) interest effect.
Indexation of the capped tariff to inflation	Implement inflation-indexed capped tariffs. Use CPI index for Luxembourg	Protect against eroding of the real value of the capped tariff over time due to inflation.
Cap fully supported by intertemporal cost allocation mechanism vs. cap is partly supported by the mechanism, remaining gap towards WTP by users is supported with additional OPEX support	Cap is fully supported by intertemporal cost allocation mechanism (minus potentially used CAPEX support deducted from RAB)	No additional OPEX support planned in LU
Risk sharing mechanism (deductible for HNOs)	Implement risk sharing mechanism	Ensure rational economic decisions by HNOs and avoid overbuilding, supplemented by a robust and rigorous scrutiny of the 10-year network developments by ILR. Open-season procedure for phase 2 to lower risk of overbuilding is considered.
Size of the deductible for network operators	Set at a level below 20% by the end of the mechanism's duration.	In case of an earlier termination by the state (opt-out), the deductible should be lowered to reduce the network operator's risk of having to cover large (unexpected) costs. In Germany, the deductible is reduced by 0.5% for every year the state choses to opt-out before the initially planned end of duration of the mechanism (2055).

Opt-out option for state or without opt-up option for state	Opt-out option for the state as of 2040 (or earlier) with reduced deductible for network operator.	A failed market ramp-up would become apparent well before the end of the 30-year duration of the intertemporal cost allocation mechanism, thus prudent to implement an opt-out mechanism complemented by a risk sharing between state and operator in the form of a deductible.
Duration of intertemporal cost allocation (payback period)	30 years	30 years (roughly) corresponds to the economic lifetime of network assets and the depreciation period (tbd by ILR)
Flexibility to adjust duration upwards and/or downward, or not	Automatic termination if amortization account is balanced. Implement upward flexibility (to the discretion of the state)	Upward flexibility accounts for potential delays in phase 2. Alternatively, specify that duration can be prolonged in case of additional or re-investments.
Frequency of review of the mechanism and its assumptions	Regular review schedule (e.g., every 2-3 years)	No-regret option to have regular reviews, thus advisable. 2-3 years seems prudent and accounts for limiting administrative effort.

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