HyDelta 2

WP2 – Hydrogen in the integrated energy system

D2.2 – Hydrogen in the energy system: value for energy transport infrastructure and its users

Status: Final

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Executive summary

This report explores the implications of clean hydrogen developments for energy transport and storage infrastructure, focusing on maximizing the value for infrastructure users and owners. Four key research questions are addressed:

1. The value of electrolysers when electricity grid reinforcements are delayed.
2. How grid operators can influence the business case and operational strategy of decentralized hydrogen production to reduce grid congestion.
3. The impact of different customer combinations on future hydrogen distribution tariffs.
4. How different customer combinations can increase the earnings of large-scale hydrogen storage capacity.

The first two research questions mainly focussed on the value of electrolysis for dealing with electricity grid congestion.

From our analysis related to the first question, we can conclude that, if electrolysers are operated based on electricity and hydrogen market spot prices alone, they will not be able to fully replace electricity grid reinforcements. This happens because the production profile of the electrolysers driven by market prices does not correlate completely with the peak load moments of the electricity cables. Moreover, locations that are suitable for electrolysis are not necessarily the locations where congestion management has most value. This has been evaluated for two cases: landfall of offshore wind and onshore combined wind and solar generation locations. Electrolysers can and do contribute to resolving congestion, but incentives of electrolysis investors and system operators do not fully align. Hence, additional price incentives at specific moments and/or locations are needed to unlock the value of electrolysers during potential periods of delayed electricity grid reinforcements.

An additional analysis was performed to assess what financial incentives could influence the business case and operational strategy of decentral electrolysis such that electricity grid congestion can be reduced. The existing GOPACS mechanism provides intraday orders which can provide attractive additional revenues for the local electrolyser business case. However, the more effective the electrolyser is in solving the local congestion by simply being active on spot markets, the less income it receives from the GOPACS orders, because there is less residual congestion. Hence, it is not expected that this congestion management mechanism will sufficiently incentivize decentral electrolyser investments. Grid operators could take a more active role to steer the locations of electrolysers, through financial or non-financial instruments. Financial instruments could include incentives that reduce grid connection costs, allow cable pooling or valorise by-products. Not all of these are compatible with the current regulatory frameworks in The Netherlands.

The second two research questions focus on the impact of different customer combinations on the hydrogen infrastructure earnings, and thereby also affecting the tariffs customers will have to pay.

It was seen that the number of connections is a major factor that impacts future gas distribution grid tariffs, because the fixed depreciation costs of the existing assets and potential grid removal costs have to be paid by less customers. Since small connections represent 98% of the connections and 85% of the allowed income of the regulated grid operators, the impact whether these type of connections (mainly represented by the built environment) will stay or leave the gas distribution grid is the biggest. Moreover, future gas distribution grid tariffs are impacted by three (interrelated) political issues: who will be burdened with the grid removal costs?; will future methane and potential hydrogen distribution grid tariffs be separate or combined?; and how fast will the existing grid value be depreciated?

Similar to revenues of large scale underground natural gas storage facilities, revenues of hydrogen storage facilities could differ greatly over the years by external market factors and perceived uncertainty in the economy. However, the fourth research activity resulted in three effects by which also customer combinations can impact the revenues of the hydrogen storage operator as well:

1. The demand for storage (capacity and volume) in the energy system relative to the available capacity, which will increase the tariffs asked for working gas volume (WGV), injection and withdrawal capacity reservations.
2. A similar timing in fixed reservations for injection and withdrawal capacity, by which more injection and withdrawal capacity can be sold and operational costs can be saved.
3. Complementary profiles that maximize the reserved and utilized WGV capacity during the year.

By reducing the need for storage and balancing portfolios with complementary variable profiles, storage operators will be able to increase their asset utilization and the impact of the storage tariffs can be reduced.

Samenvatting

Dit rapport onderzoekt de implicaties van ontwikkelingen op het gebied van schone waterstof voor energietransport- en opslaginfrastructuur, met de nadruk op het maximaliseren van de waarde voor gebruikers en eigenaren van de infrastructuur. Vier belangrijke onderzoeksvragen worden behandeld:

1. De waarde van elektrolyse-installaties wanneer versterkingen van het elektriciteitsnet worden vertraagd.
2. Hoe netbeheerders invloed kunnen uitoefenen op de businesscase en operationele strategie van gedecentraliseerde waterstofproductie om netcongestie te verminderen.
3. Het effect van verschillende klantcombinaties op toekomstige tarieven voor waterstofdistributie.
4. Hoe verschillende klantcombinaties de opbrengsten van grootschalige waterstofopslag kunnen verhogen.

De eerste twee onderzoeksvragen richten zich voornamelijk op de waarde van elektrolyse voor het omgaan met netcongestie.

Uit onze analyse met betrekking tot de eerste vraag kunnen we concluderen dat elektrolyse-installaties alleen op basis van elektriciteits- en waterstofmarktprijzen niet in staat zullen zijn om volledig netversterkingen te vervangen. Dit komt doordat het productieprofiel van elektrolyse-installaties dat wordt gestuurd door marktprijzen niet volledig overeenkomt met de momenten van piekbelasting op de elektriciteitskabels. Bovendien zijn locaties die geschikt zijn voor elektrolyse niet altijd de locaties waar congestiebeheer de meeste waarde heeft. Dit is geëvalueerd voor twee gevallen: aankomstpunt van offshore wind en op het land gelegen gecombineerde wind- en zonne-energieopwekking. Elektrolyse-installaties kunnen bijdragen aan het oplossen van congestie, maar de prikkels voor investeerders in elektrolyse en haar beheerders komen niet volledig overeen. Daarom zijn aanvullende prikkels op specifieke momenten en/of locaties nodig om de waarde van elektrolyse-installaties tijdens mogelijke periodes van vertraagde netversterkingen te ontsluiten.

Er is ook een aanvullende analyse uitgevoerd om te beoordelen welke financiële prikkels invloed kunnen hebben op de businesscase en operationele strategie van gedecentraliseerde elektrolyse-installaties, zodat netcongestie kan worden verminderd. Het bestaande GOPACS-mechanisme biedt intraday-orders die aantrekkelijke aanvullende inkomsten kunnen genereren voor de lokale elektrolyse-businesscase. Echter, hoe effectiever de elektrolyse-installatie is in het oplossen van lokale congestie door simpelweg actief te zijn op de spotmarkten, hoe minder inkomsten het ontvangt van de GOPACS-orders, omdat er minder resterende congestie is. Daarom wordt niet verwacht dat dit mechanisme voor congestiebeheer voldoende prikkels zal geven voor gedecentraliseerde elektrolyse-investeringen. Netbeheerders kunnen een actievere rol spelen bij het sturen van de locaties van elektrolyse-installaties, door middel van financiële of niet-financiële instrumenten. Financiële instrumenten kunnen incentives omvatten die de kosten van netverbindingen verminderen, kabelbundeling mogelijk maken of bijproducten valoriseren. Niet al deze maatregelen zijn echter compatibel met de huidige regelgevingskaders in Nederland.

De laatste twee onderzoeksvragen richten zich op de impact van verschillende klantcombinaties op de inkomsten van de waterstofinfrastructuur, en daarmee ook op de tarieven die klanten moeten betalen.

Er is geconstateerd dat het aantal aansluitingen een belangrijke factor is die van invloed is op toekomstige tarieven voor het gasdistributienet, omdat de vaste afschrijvingskosten van de bestaande activa en mogelijke kosten voor het verwijderen van het netwerk door minder klanten moeten worden betaald. Aangezien kleine aansluitingen 98% van de aansluitingen vertegenwoordigen en 85% van het

toegestane inkomen van de gereguleerde netbeheerders, is de impact van het al dan niet behouden van dit soort aansluitingen (voornamelijk vertegenwoordigd door de gebouwde omgeving) in het gasdistributienet het grootst. Bovendien worden toekomstige tarieven voor het gasdistributienet beïnvloed door drie (onderling gerelateerde) politieke vraagstukken: wie wordt belast met de kosten voor het verwijderen van het netwerk?; zullen toekomstige tarieven voor methaan- en mogelijke waterstofdistributienetwerken apart of gecombineerd zijn?; en hoe snel zal de waarde van het bestaande netwerk worden afgeschreven?

Net zoals inkomsten van grootschalige ondergrondse aardgasopslagfaciliteiten, kunnen inkomsten van waterstofopslagfaciliteiten sterk variëren door externe marktfactoren en de perceptie van economische onzekerheid. Echter, het vierde onderzoeksvraag heeft geleid tot drie effecten waardoor ook klantcombinaties de inkomsten van de waterstofopslagexploitant kunnen beïnvloeden:

1. De vraag naar opslagcapaciteit (zowel qua volume als capaciteit) in het energiesysteem ten opzichte van de beschikbare capaciteit, wat zal leiden tot verhoogde tarieven voor het gevraagde werkende gasvolume (WGV), reserveringen voor injectie- en onttrekkingscapaciteit.
2. Een vergelijkbare timing van vaste reserveringen voor injectie- en onttrekkingscapaciteit, waardoor meer injectie- en onttrekkingscapaciteit verkocht kan worden en operationele kosten kunnen worden bespaard.
3. Complementaire profielen die de gereserveerde en benutte WGV-capaciteit gedurende het jaar maximaliseren.

Rekening houdend met verschillende klantkarakteristieken kan de behoefte voor opslag beperkt blijven. Hierdoor kunnen opslagexploitanten hun activa beter benutten en kunnen opslagtarieven worden gereduceerd.

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1. Introduction

Clean hydrogen is seen as an important element for the transition towards a low carbon energy system. Last few years, several European and Dutch political decisions have been made that empower the early clean hydrogen developments. Examples are the provision of a EU and Dutch hydrogen strategy; roles for hydrogen in both the EU Fit for 55 and Dutch Climate Agreement ambitions; support for hydrogen initiatives provided by IPCEI funds; and support for a Dutch hydrogen transmission system and offshore production pilot.

As the development of clean hydrogen activities becomes more concrete, several questions arise about what these developments mean for existing and new energy transport and storage infrastructure. This report addresses four of these specific questions. Although the questions are different and specific, they have in common that they relate to maximizing the value of hydrogen developments for infrastructure users and/or owners. In the next paragraph the four research questions that will be answered in this paper will be introduced.

The first two research questions relate to the value of hydrogen developments to relieve pressure on the electricity grid. By the rapid increase of renewables and electrification of energy demand, the electricity grid needs reinforcements. Due to scarcity of specialized technical labour, materials and the relatively long lead times of grid reinforcements, transmission and distribution electricity grid operators face challenges keeping up the pace of demand for electricity grid reinforcement. Often it has been stated that smart positioning of electrolysers can be part of the solution. The following two research questions aim to assess to what degree such hydrogen activity can help reduce the pressure on the electricity grid in an effective manner.

1. *What value do electrolysers have if electricity grid reinforcements are delayed?*
2. *How could grid operators influence the business case and operational strategy of decentral hydrogen production for the reduction of grid congestion?*

The second two research questions relate to the value that can be captured by serving multiple type of end users simultaneously by hydrogen distribution and large scale storage infrastructure. This is relevant because if certain combinations of customers significantly improve or worsen the earning capacity of the transport and/or storage operator, it influences the transport and storage tariffs on the energy bill of future hydrogen users as well. For this assessment the existing business models of regulated natural gas distribution and commercial natural gas storage in the Netherlands are taken as starting point. Due to the difference in regulated and commercial business, value is defined differently for both infrastructure owners and so two separate research questions are answered.

3. *What is the impact of different customer combinations on the future hydrogen distribution tariffs?*
4. *How can different combinations of customers increase the earnings of large scale hydrogen storage capacity?*

In the section 2 the main insights and conclusions on the research questions are highlighted. In section 3-6 the scope, methodology, results and conclusions of every individual research question is described in greater detail.

2. Conclusions & key insights

2.1 Extra financial incentives are needed to incentivize the use of electrolysis for the reduction of electricity grid congestion

Decentral electrolysers in distribution grids could potentially play a role in the reduction of local grid congestion. Currently, the business case of local electrolysis is expected to only be feasible under specific circumstances [1]**: sufficient local green hydrogen demand and low electricity prices are key.**

With increasing amounts of decentral renewable electricity generation, as well as growing electricity demand in the Netherlands due to (amongst others) the electrification of mobility and industry, the electricity grid is becoming increasingly congested. The operation of decentral electrolysis could reduce supply congestion, by converting excess electricity from decentral wind and solar generation into hydrogen. If this conversion to hydrogen occurs close to the generated electricity, the required grid reinforcement investments could be reduced.

A review of multiple economic analyses [1] [2] [3] showed that the business case of electrolysis (with and without storage) is currently only expected to be feasible under specific circumstances. Typically, the electrolyser will only be operated when the cost of producing hydrogen from electricity is lower than the marginal revenue from the sale of hydrogen[1]. Therefore, both the hydrogen price paid by the end-user and the cost of electricity strongly determine the number of hours that an electrolyser is operational. Firstly, for a profitable business case of decentral electrolysis, there must be sufficient local demand for green hydrogen (either local buyers or a connection to a larger infrastructure system), combined with a high enough willingness to pay, which is dependent on the sector in which the end-user is active. Secondly, the electricity prices must be low enough to reach a sufficient number of operational hours. To illustrate the significant effect of electricity price scenario on the feasibility of a business case, Figure 1 shows the reduction in net present value (NPV) of an electrolyser for two different cases evaluated in a TNO study carried out for Enpuls [1] when a higher electricity price scenario is used (Figure 1, right). Lower electricity prices result in lower operational hours and thereby lower the revenues from the sale of hydrogen.

[1] Assuming that prices are not fixed through long-term contracts.

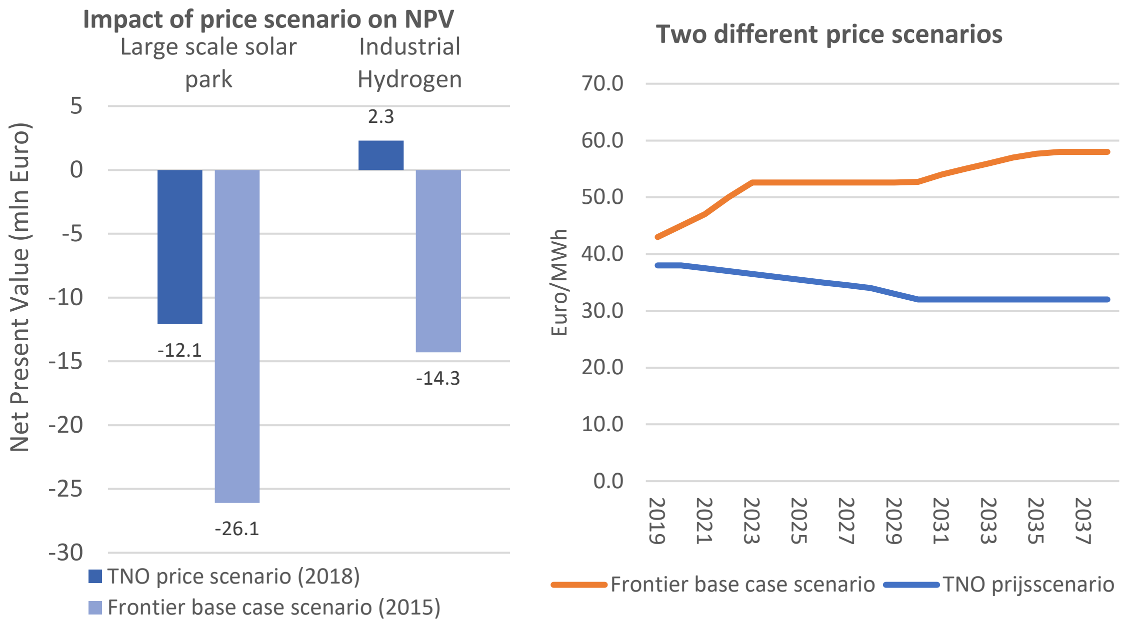

Figure 1 – Left: Impact of using different price scenarios for the calculation of the NPV of two different use cases of electrolysis [1]. Right: The two different price scenarios used to calculate the NPV in the figure on the left: TNO price scenario (2018) and Frontier base case scenario (2015) [1].

In regions where there is a lot of solar PV generation, the operational hours of an electrolyser would likely coincide with moments of supply congestion. Therefore, investment in electrolysis in strategic locations could (partially) solve local congestion issues. Congestion management services could be a means to financially stimulate the use of electrolysis for the reduction of local grid congestion. However, the current congestion management mechanism of redispatch bidding through GOPACS is not expected to directly incentivize investment decisions in new electrolysers. DSOs could provice other (financial or non-financial) incentives to stimulate electrolyser investment in the locations where this would provide most value to the system.

Since May 2022, congestion management services have become legally embedded in the Dutch electricity code [4]. Two congestion management instruments have been defined: redispatch bidding and capacity limiting contracts. For redispatch bidding, grid operators can request a congestion-order through the GOPACS platform [5] and locally connected parties with flexible electricity production, demand or storage can place responding bids. The bids are placed either voluntarily or through bid-contracts and occur on the intraday timeframe [6]. Capacity limiting contracts are short- or long-term bilateral contracts between a grid operator and a grid-connected party. The latter commits to limiting their electricity supply or demand under specified conditions or upon request of the grid operator. These requests are placed before the closure of the day-ahead market [6].

A preliminary case study on the applicability of redispatch bidding for local electrolysis was carried out, by comparing the expected operational profile of an electrolyser near a solar farm in a specific location, with the GOPACS congestion orders in that same location (see Section 3). The electrolyser is operational during times of low electricity prices, caused in part by increased solar power generation during the day and during the summer months. The GOPACS congestion orders in that location are also mainly placed during the day. It is likely that the placement of an electrolyser in that location could solve the local congestion problem for a large part, meaning that there is no further need for congestion orders and therefore no financial incentive provided by the grid operator to reduce the congestion problem. Therefore, it is not likely that this mechanism, by itself, can improve the expected business case for decentral electrolysers. It therefore does not sufficiently incentivize investment decisions in new electrolysers in strategic locations.

Aside from the existing congestion management mechanisms, the grid operator could provide an extra financial incentive in different ways. For instance, the grid operator could reduce grid connection costs or transport costs, facilitate cable pooling or enable the connection to H_2, O_2 or heating infrastructure.

One way to reduce costs of an electrolyser project is to reduce the grid costs, both for the grid connection itself, as well as the transport costs (kW_{max}, $kW_{contract}$). Especially the reduction of transport costs was shown to have a significant positive effect on the business case [1]. However, these measures are legally infeasible under current rules and regulations. It would be difficult to come up with general terms and conditions that would have the desired effect in all situations [1]. Another option to reduce grid costs of the electrolyser, is to share the grid connection with another party, for instance with local renewable energy producers. Currently, so-called 'cable pooling' is only legal for wind- and solar parks, so broadening the legal scope of this construction would be necessary in order to benefit electrolyser projects. Efforts to implement this are already on the way. A one-off reduction in connection cost is another option which may be suitable in circumstances where connection costs form a particularly large fraction of the investment cost.

If grid operators would take on the task of hydrogen transport and distribution, this could reduce the hydrogen transport costs of the hydrogen producer. Furthermore, the reviewed analyses indicate a necessity for 'value stacking' for a feasible business case, which means that the electrolyser is operated in such a way that it receives multiple revenue streams aside from the sale of hydrogen. Examples include the valorization of by-products, such as oxygen and heat. If the grid operator would facilitate the development of or connection to existing O_2 and heating infrastructure, this could help attract investments in local electrolysers.

2.2 If hydrogen distribution grids are established, decisions of users in the built environment can impact its tariffs significantly

At the moment of writing this paper (2023), no decision has been made yet if regulated hydrogen distribution grids will be established in the Netherlands. An analysis was performed to investigate the development of future gas distribution grid tariffs, based on the existing way of gas distribution regulations, the II3050 International ambition scenario[2] and some required assumptions (for example that hydrogen distribution will be a regulated business). **The assessment showed that especially developments in the built environment can impact gas distribution tariffs significantly, because they represent 98% of the existing connections and 85% of the total allowed income by the distribution grid operators. Especially when a relatively large grid area is converted to hydrogen with a relatively low number of connections, the grid tariffs may rise.** This could for example be the case if a certain area is determined to be converted to hydrogen, but a lot of customers decide to leave the grid and go full electric: the transport service costs remain the same but are allocated to a lower number of customers. Due to the limited number of larger connections, a less significant impact was seen for sectors such as the local industries and refuelling stations.

Figure 2 shows the potential development of methane distribution grid tariffs under our scenario assumptions: the tariffs can increase significantly when the depreciations costs of existing assets and grid removal costs have to be paid by a lower number of customers.

[2] Note that this is the II3050 scenario that involves the biggest role for molecule/hydrogen distribution.

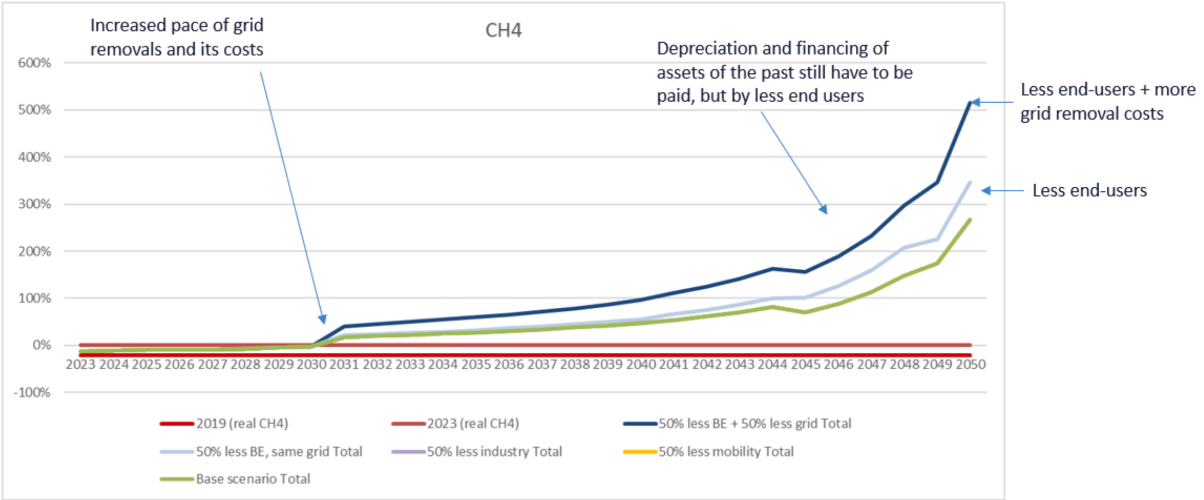

Figure 2 – Methane distribution grid tariff development depended on the degree whether several types of end users switch to hydrogen or not

Figure 3 shows the potential development of hydrogen distribution grid tariffs under our scenario assumptions: the tariffs start relatively high due to the existing value of converted gas assets but decrease gradually towards the existing natural gas grid tariff levels. However, this strongly depends on the density of customers connected to the grid and the grid conversion costs.[3]

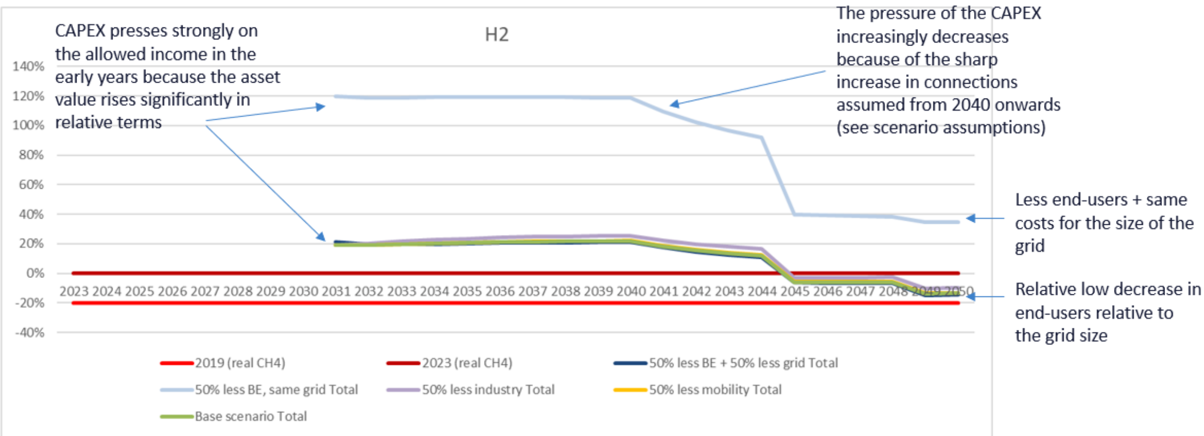

Figure 3 – Hydrogen distribution grid tariff development depended on the degree whether several types of end users switch to hydrogen or not

Further, we highlighted the following political issues with regards to the future of gas distribution grids:

1. **Removing the total gas distribution grid and its connections theoretically costs 20 B€ and its current asset value represents 8.3 B€. An impactful question for the tariffs of the decreasing number of (renewable) gas distribution grid users raises whether they pay the whole bill of removal or the general tax payer.**
2. **Should mutual or separate gas distribution tariffs for methane and hydrogen be applied?**
3. **How strong should degressive depreciation be applied, given that the Netherlands has no vision how fast and how much customers will leave the gas distribution grid?**

[3] Connection conversion costs were estimated €255 per connection [14] but if this will turn out to be €900 per connection based on more recent insights 2050 hydrogen grid tariffs will be +26% compared to 2023 instead of -14%.

2.3 Three effects should be considered related to large scale hydrogen storage in the future Dutch energy system

In the Netherlands large scale underground natural gas storage is a commercial activity in which the storage operator sells its capacity to a range of customers. If we assume potential future large scale underground gaseous hydrogen storage will offer similar kind of services, **we found three effects in which different combinations of customers can increase the earnings of large scale hydrogen storage capacity**:

4. The demand for storage (capacity and volume) in the energy system relative to the available capacity, which will increase the tariffs asked for working gas volume (WGV), injection and withdrawal capacity reservations.
5. A similar timing in fixed reservations for injection and withdrawal capacity, by which more injection and withdrawal capacity can be sold and operational costs can be saved.
6. Complementary profiles that maximize the reserved and utilized WGV capacity during the year.

Hydrogen storage operators can use these insights, but these effects are to a large extend influenced by external factors out of influence of the storage operator itself. However, the effects can be used for energy suppliers or traders optimizing and balancing their portfolios, or in the design and target setting for the Dutch and North Western European energy system. Since it turned out that certain combinations of customers have complementary supply and demand characteristics (e.g. solar and wind, or wind and the built environment). Therefore, they can reduce the total need for storage and/or spread out storage demands out over time. This should be beneficial for the storage operator its earnings and the pressure of the storage tariffs on the end users hydrogen bill.

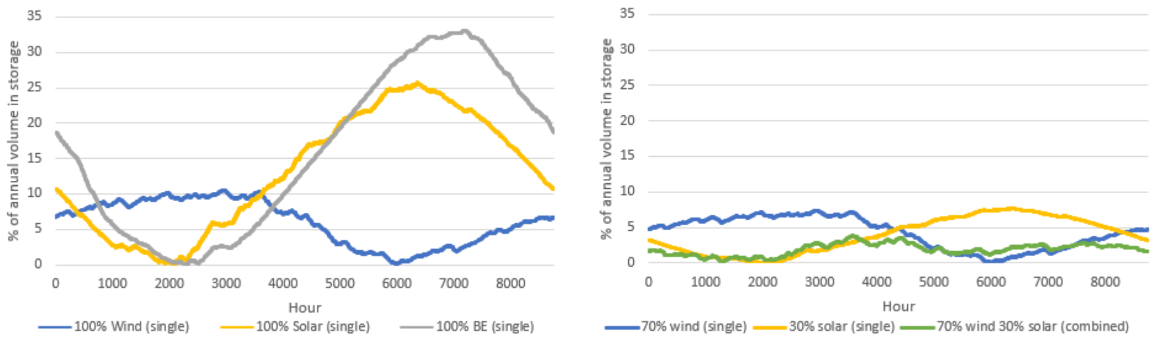

Figure 4 – Illustration of individual storage profiles (left) versus combining complementary profiles (right, example of solar and offshore wind)

3. Value of electrolysers for delay in electricity grid reinforcements

3.1 Research question and scope

This analysis considers the viability of electrolysers in partnership with wind and solar to help reduce congestion in the electricity grid. Already in today's system in the Netherlands, congestion occurs. So far it has been predominantly driven by subsidy-driven investments in solar parks, resulting in infeed congestion from decentralized peripheral nodes with lower costs (e.g., for land lease) to the national high-voltage network. The ambitious plans for future development of offshore wind (beyond 2030) with a more centralized character may also turn out to be hard to accommodate from a network perspective. Investment in electrolysers in renewable energy generation pockets (i.e. near decentralized renewable clusters on land or the more centralized offshore wind landing points) would provide for an efficient market-based response to the emergent congestion. In this analysis we explore the impact of such investments in two scenario's, compared to a base case without electrolyser investments:

1) Electrolysis for Offshore Wind
2) Electrolysis for Wind and Solar

The electrolyser investments and deployment should, in principle, result in a reduction of congestion and convergence of electricity prices at times of high renewable electricity infeed.

3.2 Methodology

I-ELGAS is an integrated electricity, gas, and hydrogen market model that was developed to analyze the interactions between these three energy carrier markets. Figure 7shows a compact overview of the model. For a full description of the model formulation see [7].

I-ELGAS minimizes the marginal cost of the combined market system and produces the optimal prices (marginal costs) and production dispatch. The optimization is performed on a yearly basis, with hourly market clearing granularity. I-ELGAS models the Netherlands with 35 electricity, 24 methane, and 19 hydrogen nodes, connected in their respective geographical grids. It also includes neighboring North Sea countries as single nodes that can trade with each other and with the Netherlands. Energy can be transferred between the grids by means of conversion technologies, such as electrolysers and CHPs.

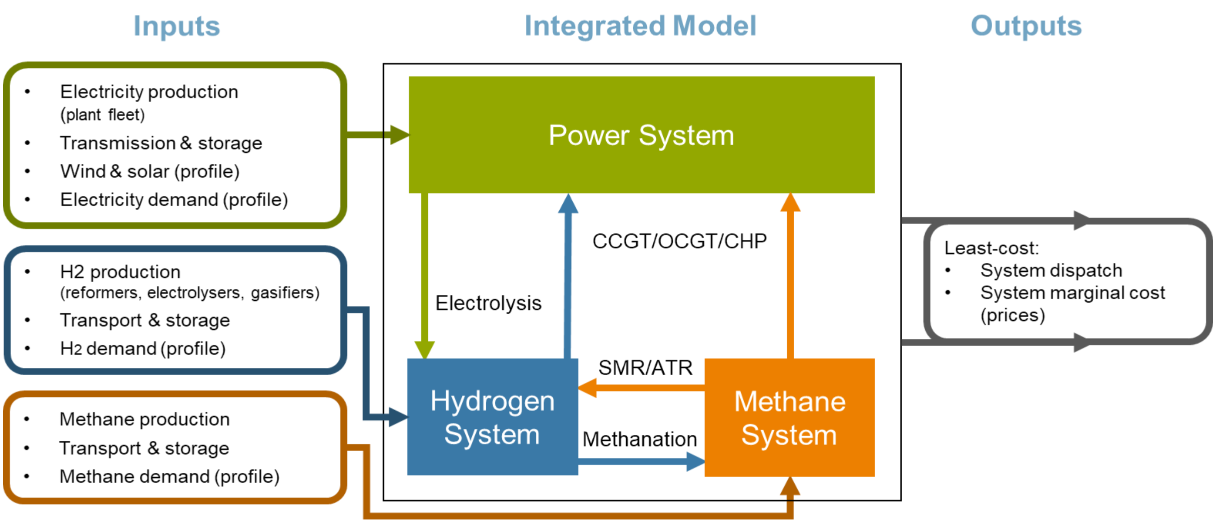

Figure 5 - An overview of the I-ELGAS model

Hence, so-called locational marginal pricing is applied in the model, reflecting the least-cost system allocation.

- As long as no congestion occurs, least-cost deployment of the overall supply in the system as a whole results, with least-cost generation in nodes with ample low-cost supply (the generation pocket or gen pocket in short) that is transported to nodes with high demand (the load pocket) and all energy prices across the nodes;
- If congestion between two nodes occurs, transport capacity falls short to allow for this energy transport in full so that assets with higher marginal cost of production in the load pocket are deployed, while units with highest marginal cost of production in the gen pocket are no longer deployed. Accordingly, congestion induces higher energy prices in the load pocket and lower prices in the gen pocket.

Locational marginal pricing applies to current pricing practice across borders in the EU electricity and natural gas markets; within individual Member States locational - or zonal marginal pricing is not implemented, though a process was initiated to assess alternative bidding zones since 2019[4]. Locational - or zonal marginal pricing reflects the market-based value of energy in a congested energy system, and incentivizes market-based supply and demand investments as well as operation of existing assets in response to congestion.

3.2.1 Model assumptions

Since the year and system are optimized as a whole, the model assumes perfect foresight, meaning actors do not have any uncertainty about conditions and marginal costs later in the year. This means that there is no (volume) risk and associated risk premia considered in the market.[5] The model only generates the system marginal cost of production, that may be taken as a proxy for commodity pricing under perfect competition. Dynamics of scarcity pricing, i.e. high prices that may result in actual markets at times of scarce supply, are not included in the model. Hence, these limitations in our modelling approach imply that validity of the delta analysis on scenario's with and without electrolysers can only be assured, assuming sufficient storage capacity is available and markets are competitive.

3.3 Results & discussion

3.3.1 Electrolysis for Offshore Wind

For the Offshore Wind Scenario, electrolysers were distributed according to the landing areas for offshore windpower, and scaled by the size of the wind farms. Figure 6 shows the prices of electricity as well as the stacked electrolyser load for all locations (hence, representing total electrolyser load in the Netherlands).

Prices in each location are sorted separately from high to low to generate its price duration curve, and the electrolyser load for that location is sorted with the price. The yellow line marks the approximate electricity price below which the electrolysers turn on – around €64. This price is approximate, and on par with marginal cost of sea imports. Each locational marginal price drops below this price at different times, with Beverwijk, Botlek, Eemshaven, and Ossendrecht individually reaching full load for 2065, 1955, 893, and 2270 hours respectively.

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[4] Following the implementation of Commission Regulation (EU) 2019/943 (Electricity Regulation under the Clean Energy Package), all TSOs have to conduct a common study on alternative BZ configurations: the so-called bidding zone review (BZR).

[5] This is a common assumption in energy market models to ensure separability of time periods; in practice, this only has a major impact when modelling decisions that have to be taken a significant amount of time before the benefits of those decisions are realized. In our setup, this particularly concerns storage, which is present in limited quantities – the model will not use storage capacity to hedge, e.g., demand volume risk, and therefore generally have lower storage levels than could be expected in a real-world setting.

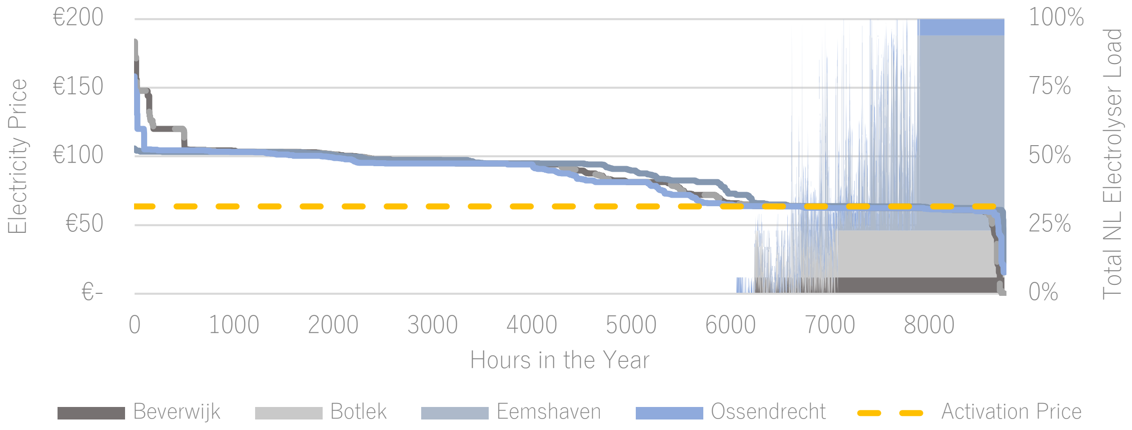

Figure 6 – Wind Scenario: Electrolyser usage compared to regional electricity prices

Figure 7 shows the total electricity out-flow of the Eemshaven node, as an example for the impact of electrolyser deployment on infeed congestion. The electricity out-flow duration curves are sorted separately for both scenarios, with the electrolyser load (grey) sorted with the out-flow of the electrolyser scenario (yellow). The yellow line, dropping significantly below the blue line in the grey areas indicating electrolyser deployment, shows that electrolyser deployment can reduce electricity flow. The plateaus show the maximum capacities of Eemshaven's connections (NED, DEN, NOR).

However, approximately 3300 hours show peak flow with negligible electrolyser load. This means that even though electrolysis is available, it is not being used consistently to reduce peak electricity flow when reacting to electricity prices. This is due to interactions between the Netherlands electricity price and foreign electricity prices, due to interconnections between Eemshaven and Norway and Denmark. Low electricity prices in the Netherlands sometimes lead to exporting electricity to Denmark and Norway before electrolysers turn on (high out-flow, without electrolysis). Similarly, electrolysers sometimes respond to low electricity prices caused by importing electricity from Denmark and Norway.

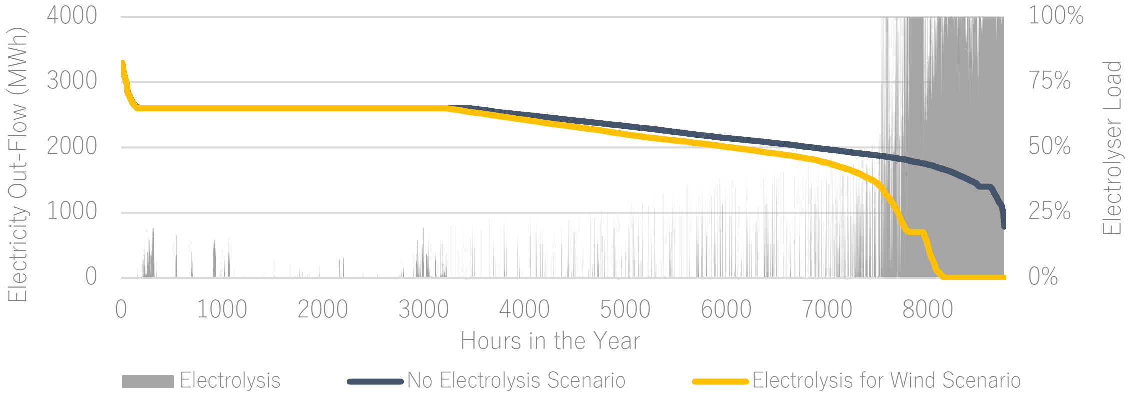

Figure 7 – Wind Scenario: Electrolysis impact on electricity flow (Example: Eemshaven)

3.3.2 Electrolysis for Wind and Solar

For the Wind and Solar Scenario, electrolysers were distributed and scaled according to all wind and solar regions. In this scenario, electricity prices were different for only two regions, which can be labeled East and West. Note that this already shows that the adjusted distribution of electrolysers results in a lower number of congestion area's than the previous example.

Figure 8 shows a similar trend to Figure 6: as before, the approximate electricity price for activation of electrolysis is €64 and the west's lower electricity prices spend more time below this price. The West and East regions individually reach full electrolysis load for 1,417 and 865 hours respectively.

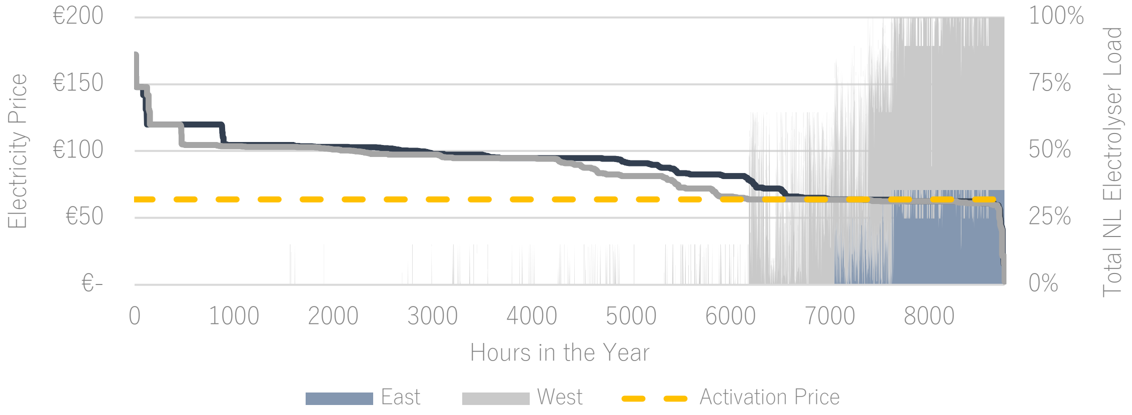

Figure 8 - Wind & Solar Scenario: Electrolyser usage compared to regional electricity prices

Figure 9 shows the impact of electrolysis on the electricity out-flow of Ossendrecht. The peak is when both the connections to Belgium and to the Netherlands are at full capacity, the plateau is when the connection to the Netherlands is at full capacity. Electrolysis production at Ossendrecht (grey) is sorted by the total electricity outflow of the electrolysis scenario (yellow). Similar to Figure 7, the yellow lines dropping below the blue lines show that electrolysis is reducing the flow along these connections.

However, there are still 3560 hours when the Netherlands connection is at full flow capacity, whether electrolysis is running or not. In this scenario, flow and electrolysis are being impacted by electricity prices in Belgium. There are periods of the Netherlands importing electricity from Belgium, resulting in high flow from Ossendrecht into the Netherlands – regardless of whether electrolysers turn on. This shows again that although electrolysis can potentially reduce congestion, it does not necessarily do so; and operating electrolysis based on electricity prices results in many hours with high flow, but no electrolysis.

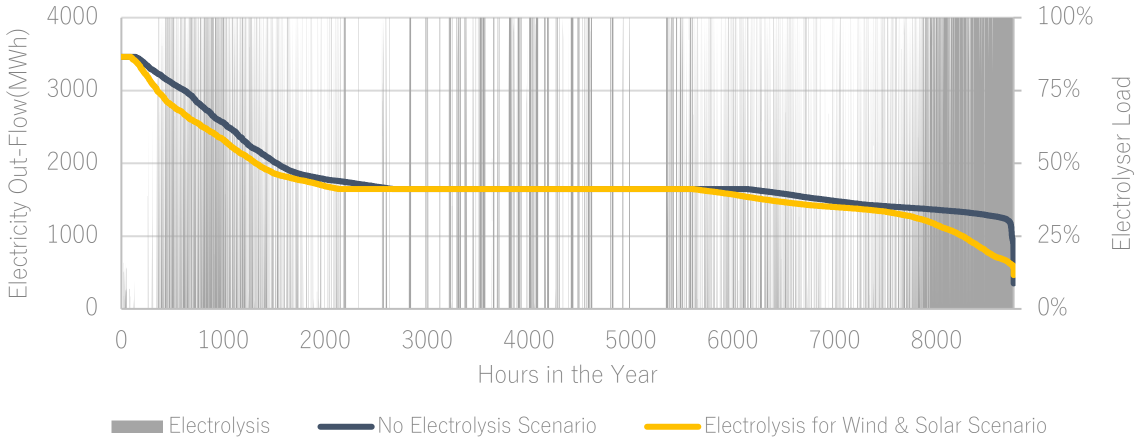

Figure 9 - Wind & Solar Scenario: Electrolysis impact on electricity flow (Example: Ossendrecht)

3.4 Conclusions

These analyses indicate the following:

1) Distributing electrolysers according to combined wind and solar capacity reduces electricity grid congestion more than distributing them by only offshore wind production.
2) Electrolysers can reduce congestion, but do not run to their full potential when only acting in response to low electricity prices.
3) Interactions between local and foreign electricity prices impact electricity flows and congestion, complicating the response of electrolysers to low electricity prices caused by renewable energy producers in regions with interconnection capacity.

4. Operation of electrolyser for congestion management

4.1 Research question and scope

With increasing amounts of decentral renewable electricity generation, as well as growing electricity demand in the Netherlands due to (amongst others) the electrification of mobility and industry, the electricity grid is becoming increasingly congested. The operation of decentral electrolysis could reduce supply congestion, by converting excess electricity from decentral wind and solar generation into hydrogen. If this conversion to hydrogen occurs close to the generated electricity, the required grid reinforcement investments could be reduced.

Therefore, this section tries to answer the following research question:

''How could grid operators influence the business case and operational strategy of decentral hydrogen production for the reduction of grid congestion?''

This analysis provides a basic understanding of the electrolyser business case, as well as the possibilities that grid operators have to incentivise the development of electrolyser projects in locations where electrolysis could help reduce grid congestion.

4.2 Methodology

First, a literature review of different electrolysis studies within TNO was carried out and the feasibility of the different business models was compared. The analysed studies were:

- TNO, „Waterstof uit elektrolyse voor maatschappelijk verantwoord netbeheer - business model en business case," TNO, 2018.
- TNO, „Techno-Economic Modelling of Large-Scale Energy Storage Systems," TNO, 2020.
- TNO, „Offshore wind business feasibility in a flexible and electrified Dutch energy market by 2030," TNO, 2022

Additionally, the different ways for grid operators to influence the business case were taken from the TNO study for Enpuls [1], but were updated with information on the recently implemented congestion management mechanisms and supplemented by case study, explained in the next paragraph.

Secondly, a preliminary case study was done to assess the impact of bidding into the GOPACS market on the operational strategy and business case of an electrolyser. A specific location was selected: a solar park at Vlagtwedde [8], because there are many redispatch orders on GOPACS for this locations and one of the case studies of the TNO study for Enpuls concerns the same location [1]. A business case model for an electrolyser at Vlagtwedde was run using an updated electricity price scenario from TNO, which determined the operational profile of the electrolyser. This was compared to the redispatch orders on the GOPACS platform in that location. Only one case was selected, because there is not a lot of data available on the GOPACS platform. This means that the results of the analysis are not universal and should be corroborated by further research with multiple case studies.

Thirdly, a workshop was organized to bring together different stakeholder perspectives on decentral electrolysis, which were encountered within HyDelta2.0 and HyScaling, a parallel research project [9]. Where HyDelta is focused on grid operators, the HyScaling consortium consists mainly of businesses from the electrolyser supply chain. The workshop participants included regional grid operators, electrolyser project developers, parties within the electrolyser supply chain, energy producers and research institutes. The goal of the workshop was to jointly identify opportunities and actions that could be undertaken to further develop electrolysis in the distribution grid, and thereby accelerate the local energy transition.

4.3 Results & discussion

4.3.1 Literature study

The review of multiple economic analyses [1] [2] [3] showed that the business case of electrolysis (with and without storage) is only expected to be feasible under specific circumstances. Typically, the electrolyser will only be operated when the cost of producing hydrogen from electricity is lower than the marginal revenue from the sale of hydrogen. Therefore, both the electricity prices and hydrogen price paid by the end-user strongly determine the number of hours that an electrolyser is operational. Therefore, for a profitable business case of decentral electrolysis, there must be sufficient local demand for green hydrogen, combined with a high enough willingness to pay, which is dependent on the sector in which the end-user is active. Additionally, the electricity prices must be low enough to reach a sufficient number of operational hours. To illustrate the significant effect of electricity price scenario on the feasibility of a business case, Figure 1 shows the change in NPV of two different cases (taken from [1]). Lower electricity prices result in lower operational hours and thereby lower revenues from the sale of hydrogen.

As we have seen above, electrolysers that are already available at a particular location can contribute to congestion management. This additional value could provide an additional financial incentive if it can be captured. For new electrolysers, this has the added benefit of attracting electrolysers to the location where they have most value to the electricity system. The grid operator could provide an extra financial incentive in different ways. For example, through existing congestion management mechanisms, which have become legally embedded in the Dutch electricity code since May 2022 [4]. Two congestion management instruments have been defined: redispatch bidding and capacity limiting contracts. For redispatch bidding, grid operators can request a congestion-order through the GOPACS platform [5] and locally connected parties with flexible electricity production, demand or storage can place responding bids. The bids are placed either voluntarily or through bid-contracts and occur on the intraday timeframe [6]. Capacity limiting contracts are short- or long-term bilateral contracts between a grid operator and a grid-connected party. The latter commits to limiting their electricity supply or demand under specified conditions or upon request of the grid operator. These requests are placed before the closure of the day-ahead market [6].

Additionally, the grid operator could reduce grid connection costs or transport costs. Especially the reduction of transport costs was shown to have a significant positive effect on the business case [1]. However, these measures are legally infeasible under current rules and regulations. It would be difficult to come up with general terms and conditions that would have the desired effect in all situations [1].

4.3.2 Case study

For this case study, an existing electrolyser business case tool was used, which was developed for [1]. This model was updated with an electricity price scenario for 2030, which was simulated using TNO's market model simulation tool, EYE. In this case study, the electrolyser is placed near a large scale solar park, at Vlagtwedde. It is assumed that 216 ton of the hydrogen volume is sold to a nearby H_2 refueling station for 5 EUR/kg and the rest is sold to industry for the reference price of grey hydrogen from natural gas reforming plus the ETS price. The resulting operational profile showed that the electrolyser would turn on during hours of low electricity prices, which occur most often during the day and during the summer months. This operational profile does not take into account ramping rates of the electrolyser, but assumes it can be switched on and off instantly.

This operational profile was then compared to GOPACS congestion orders at Vlagtwedde, shown in Table 1. These orders are mainly placed during the day, because the congestion is likely causes by the large solar park located there.

Table 1 – GOPACS buy orders at location Vlagtwedde [5].

	GOPACS buy orders Vlagtwedde		
Date	**Hour start**	**Hour end**	**MW**
22-6-2022	12:00	14:00	1
5-7-2022	13:00	14:00	2
5-7-2022	14:00	15:00	1
15-7-2022	12:00	13:00	1
19-7-2022	12:00	14:00	0,5
20-7-2022	12:00	14:00	0,4
21-7-2022	15:00	17:00	0,5
22-7-2022	12:00	15:15	0,5
26-7-2022	12:00	15:00	3
28-7-2022	12:00	17:15	3
29-7-2022	10:30	18:00	2
2-8-2022	08:00	18:00	1,5
3-8-2022	09:00	17:15	1
5-8-2022	09:00	18:15	1
9-8-2022	09:15	18:00	1,5
10-8-2022	11:00	20:15	1,4
12-8-2022	10:30	18:30	1,4
13-8-2022	10:00	18:15	2
18-8-2022	08:00	17:15	1,7
19-8-2022	08:00	12:00	1,7
13-12-2022	12:00	13:00	4

Table 2 shows the operational hours of the electrolyser between 8:00 and 18:00 for the same dates as the GOPACS congestions orders.

Table 2 – Operational hours of a hypothetical electrolyser of 25 MW, near solar park Vlagtwedde. Electrolyser is on when marginal costs are lower or equal to marginal revenue from the sale of hydrogen, using business case model developed by TNO. (Operational profile does not take into account ramping rates.)

	Green = Electrolyser on. White = Electrolyser off										
Date	**8:00**	**9:00**	**10:00**	**11:00**	**12:00**	**13:00**	**14:00**	**15:00**	**16:00**	**17:00**	**18:00**
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The overlap between the congestion management orders and the operational hours of the electrolyser, in this particular location, as calculated by the model, is **66%**. If an electrolyser of 4 MW (the highest capacity of the GOPACS buy orders) were placed in that location, it would implicitly solve a large part of the local congestion problem, because it would already be operational at times when there would otherwise have been congestion. This means that it would receive no financial incentive provided by the grid operator for those hours. During the hours that there is a congestion order, but the electrolyser is not operational because the electricity price is too high, it could obtain a financial incentive to dispatch the electrolyser to absorb the excess electricity in the local grid. These are the hours where the local congestion and the electricity price do not coincide.

4.3.3 Workshop

The goal of the workshop was to jointly identify opportunities and actions that could be undertaken to further develop electrolysis in the distribution grid, and thereby accelerate the local energy transition. The main actions that were defined by the group were:

- **Realize governance in the development of decentral electrolysis projects**
  Due to the many identified uncertainties and barriers on different topics a lack of governance on decentral electrolysis is identified by the participants. There is a need for a coordinating party, which can integrate renewable energy plans, hydrogen demand development, grid congestion information and hydrogen infrastructure roll-out. The role to govern the development of decentral electrolysers can be taken by different parties, in the session it was suggested that the role can be at: grid operators (until 2030), project developers or Provinces.
- **Increase green hydrogen demand**:
  Local green hydrogen demand is the main driver for decentral electrolysis, value from other streams such as congestion management is an additional benefit. Therefore, green hydrogen demand with a sufficient willingness to pay is pivotal for the development of decentral electrolysis.
- **Matching location of hydrogen demand and preferred congestion locations by the grid operators:**
  To compete with large scale electrolysis, additional value is needed to be developed for local electrolysis. This can be security of supply or closeness (less transport costs), or value from gid congestion services. To target the location of electrolysis to these locations a match of hydrogen demand and preferred congestion locations is needed.

Furthermore, the workshop group discussed the potential incentives which can be employed from the grid operator to improve the electrolyser business case, at locations where it contributes to solving congestion. The following incentives were discussed:

- **Cable pooling:** By means of cable pooling a wind and solar farm can share one grid connection. This construction can reduce the total grid connection cost compared to a situation in which the cable is not pooled. At the moment cable pooling with electrolysis is not legally embedded, although this is likely to change in the near future.
- **Facilitate H_2, O_2 or heating infrastructure:** From business case analysis, the transport of hydrogen to the customer is an important cost driver. Facilitating hydrogen infrastructure can make the transportation cost more accessible. Oxygen and heat are residual products from electrolysers, which can be utilized if suitable infrastructure is available, facilitating such infrastructure provides additional value to the electrolyzer case.
- **Facilitate blending hydrogen in the natural gas grid:** As an additional value stream, blending of hydrogen in the natural gas grid was proposed. Several barriers were mentioned for this incentive, such as the decreased value of blended hydrogen and the costs to organize a system which maintains a fixed percentage of hydrogen in the grid.
- **Ancillary services:** During the discussion it was mentioned that electrolysers can provide both congestion management to the regional grid operator as ancillary services for the TSO. From a perspective of the electrolysers operator these markets are both feasible as additional value stream, while the resulting operational strategy can conflict with the goals of the grid operators.

4.3.4 The role of hydrogen storage

The analysis above has considered the business case for electrolysis only. Hydrogen storage, at both small and large scales, is another key component of the future hydrogen system. As HyDelta 2 deliverable 3.2 has shown, the business case for hydrogen storage based only on the value of arbitrage in hydrogen markets is even worse than the business case for electrolysis, at least in the near future. This is a result of low variability in hydrogen prices, which is expected to stay low as long as hydrogen imports and hydrogen production from natural gas still set prices during most of the year, i.e., while the amount of electrolysis capacity is still low. We have therefore not explicitly analyzed this business case again for this report.

However, hydrogen storage is a key component of a functional hydrogen system. Local hydrogen storage will likely be needed to balance short-term variations in demand and supply, and large-scale storage of hydrogen or hydrogen carriers is one of only a small number ways to efficiently store energy across seasons or even years in the climate-neutral energy system we want to operate in the future. The value of storage for security of supply is therefore high, especially beyond 2030. Since revenues from arbitrage are likely to be low in the short term, while lead times for especially large-scale storage are long, additional revenue streams or forms of public finance will be needed to support hydrogen storage. As suggested in HyDelta 2 deliverable 3.2., this could take the form of system operators booking storage capacity through long-term contracts to enable security of hydrogen supply and charging system users for this. This is already common practice in gas systems. Subsidies or other types of support with public money are an alternative, particularly in early stages, especially if storage facilities contribute to national security.

4.4 Conclusions

Decentral electrolysers in distribution grids could potentially play a role in the reduction of local grid congestion. However, the business case of local electrolysis is expected to only be feasible under specific circumstances [1].

In regions where there is a lot of solar PV generation, the operational hours of an electrolyser would likely coincide with moments of supply congestion. Therefore investment in electrolysis in strategic locations could (partially) solve local congestion issues. Congestion management services could be a means to financially stimulate the use of electrolysis for the reduction of local grid congestion. However, the current congestion management mechanism of redispatch bidding through the current GOPACS platform is not expected to significantly incentivize investment decisions in new electrolysers, because electrolysers are not rewarded for the congestion they resolve by simply responding to spot market prices.

Aside from the existing congestion management mechanisms, the grid operator could provide an extra financial incentive in different ways. For instance, the grid operator could reduce grid connection costs or transport costs, facilitate cable pooling or, in the future, enable the connection to H_2, O_2 or heating infrastructure.

5. Impact different customer combinations on distribution grid tariffs

5.1 Research question and scope

Distribution grid operators (DSO) in the Netherlands perform the regulated activity of distributing energy in the form of electricity and natural gas to more than 8 million connections for the electricity and natural gas grid each. The natural gas connections involve households, residential buildings, industry, CNG fuelling stations and feeders of biomethane. In the future next to methane, also hydrogen might become an energy carrier that requires a distribution grid to deliver it to end users in an economical and efficient manner. In HyDelta 1 it was investigated that there are cost benefits in connecting multiple type of end users to the same grid. Figure 10 shows that especially the large volumes of industrial customers can reduce hydrogen transport costs per kg significantly for end users with smaller volumes.

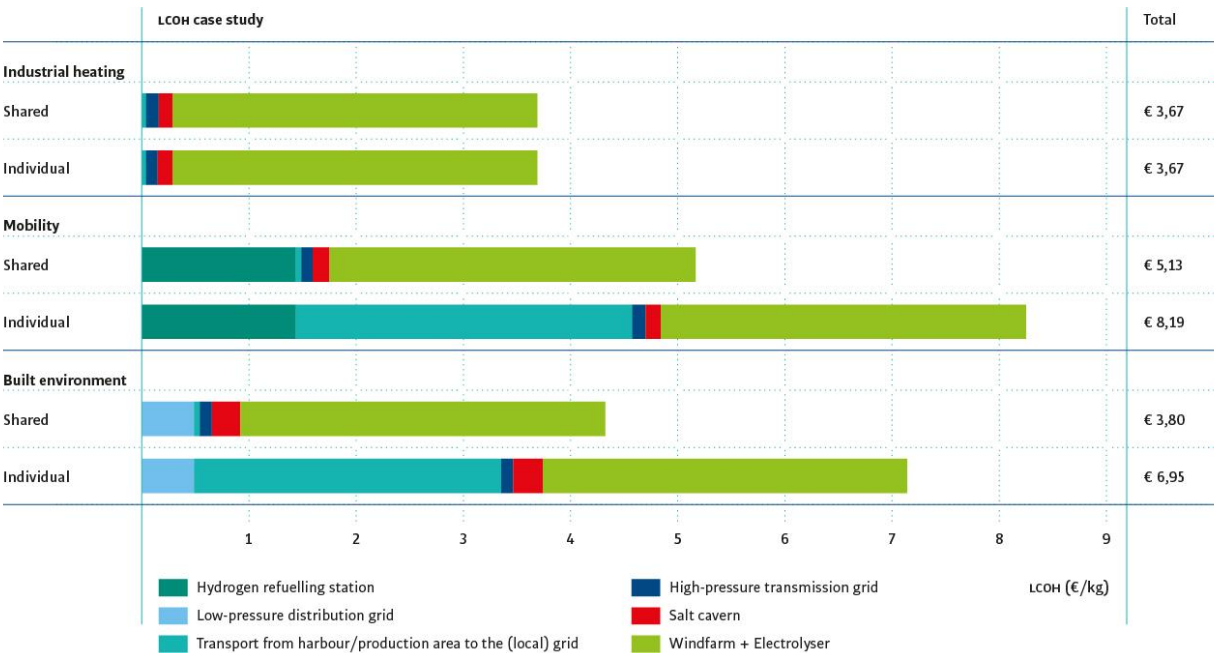

Figure 10 – Hydrogen supply chain costs for different applications if last mile pipeline can or cannot be shared with other end users [10]

However, natural gas distribution is a regulated business and if hydrogen distribution will become a regulated business as well, the transport costs for end users are not determined by its specific pipeline and distance,[6] but every consumer will pay the same tariff for an equal type of connection. Therefore, in order to assess what future hydrogen users might pay for transport it is relevant to investigate the possible impact of different types of end users on the future grid tariffs as well. That is why the following research question will be answered in this section:

''What is the impact of different customer combinations on the future hydrogen distribution tariffs?''

As it is currently undecided if there will be hydrogen distribution grids in the future and under what exact conditions these grids will or should be regulated, we take into account in this study that a potential hydrogen distribution grid will be regulated similar to the natural gas distribution grid nowadays. There might be differences in reality. Although, this approach is chosen as it is expected to give practical insights for the Dutch context and thereby can provide insights on what differences might be taken into account if hydrogen distribution grids would become regulated in the future.

[6] Except for the last meters of the individual connection if this contains more than 25 meters.

5.2 Methodology

The research question has been answered by three steps. The first step was to investigate how the business of natural gas distribution grid operators is regulated currently. This has been done by the public information and publications by the ACM and an interview with one of the tariff calculators of the distribution grid operators. The second step was to calculate future grid tariffs, taking into account the relevant characteristics of this research question. Thirdly, the results were discussed and compared with insights from previous studies related to the topic. In the following subsections the approach and assumptions to calculate future grid tariffs is explained in greater detail.

5.2.1 The regulated business of natural gas distribution

The Dutch natural gas distribution operators are regulated such that they have a monopoly position for natural gas distribution in an agreed area, but their tariffs are regulated to keep their operations reasonable, to stimulate efficiency and ensure enough income for the DSO's to remain security, quality and sustainability of the grid [11] [12]. The tariffs are decided in three steps (see Figure 11):

1. Method decision
   This decision is published for a period of 3 to 5 years and describes how the allowed revenue of the grid operator is determined based on the efficient costs, for the next years.
2. X-factor decision
   The X-factor decision is also made very 3 to 5 years. It determines for every single grid operator what the method decision means for its allowed income. This income is based on the expected effective costs and number of customers, corrected by an annual tariff cut (the x-factor), inflation and in case of the electricity grid also a q-factor.
3. Tariff decision
   During the regulatory period of the method decision and X-factor decision, every year the allowed income of the grid operator is calculated by the X-factor and corrected by several developments that were not taken into account at the start of the regulation period. Some examples for the natural gas grid operator in the last years are: local charges, additional costs for grid removals and costs of energy losses. The allowed income is distributed over the different types of customers as decided in the X-factor decision. There is some small room for individual grid operators to modify tariffs of specific services, as long as in the end their quantities and tariffs align with their allowed income.

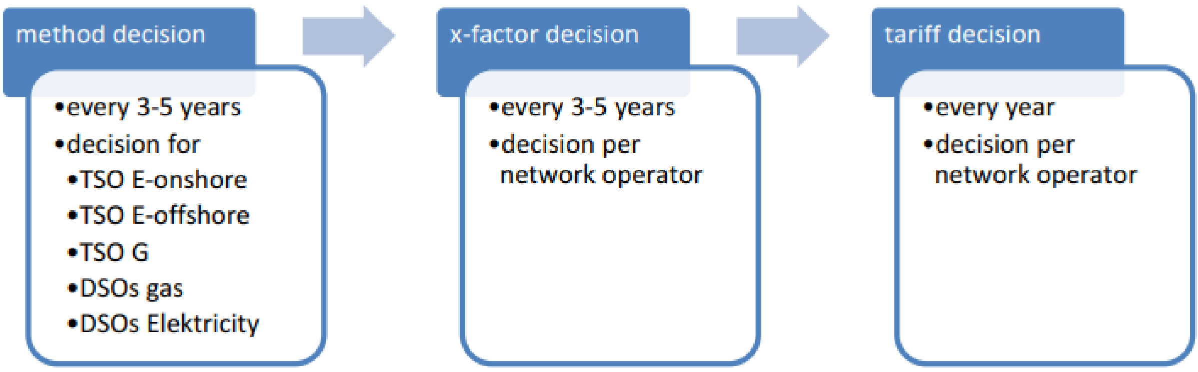

Figure 11 – Three steps to regulate grid tariffs in the Netherlands

The natural gas DSOs offer two types of services: transport services and connection services. The transport services are divided in a fixed tariff (€/year) and a capacity tariff (€/year/capacity) for each type of connection (small, large profile and large telemetric). The connection services are divided in one-time connection tariffs for new connections and periodic connection tariffs (€/year) for each type of connection. Moreover, if a new connection exceeds a predefined length (currently 25 meters), an additional one-time connection tariff based on the length (€/m) of the connection is billed.

More specific information on the regulation of natural gas distribution grid operators and their tariffs can be found on the website of ACM.

5.2.2 Calculation methodology and assumptions

The development in methane and hydrogen distribution grid tariffs in this study are calculated based on the existing procedure used for the natural gas distribution grid; and based on different future scenario's for customers connected to the distribution grid. However, this cannot be done without making some assumptions. Therefore, we highlight the most crucial assumptions that were made:

- In reality, every 3-5 years a new method decision is made which can impact the way grid tariffs are calculated. As we do not know the future method decisions that will be made, we stick to the calculation methodology in the existing method decision (2022-2026).
- Similar is done for the X-factor decision. We assume an weighted average X-factor of 2.09 (among the different DSOs) based on the current X-factor decision. And we assume CPI/inflation of 2% and a WACC of 4% as most typical values over the long term.
- ACM states in the existing method decision that the costs of maintaining and reinvesting in the grid are expected to scale linear by the total size (transport service) and connections (connection service) [13]. We assume this as well in our calculations.
- The depreciation costs in the future will depend on when investments have been done in the past and how quick they are depreciated. We do not have this information. Therefore, we assumed that the existing assets will be depreciated in the same pace as in the last X-factor decision. The standardised asset value for transport service assets was 6.61 B€ and 1.65 B€ for connection service assets in 2022. In the method decision of 2022-2026 it was decided to use variable declining balance (VDB) depreciation compared to linear depreciation. This is a degressive depreciation methodology that enables to depreciate faster in the earlier years. This was mentioned to be more fair to the situation of a declining number of connections, as the investment costs are spread more equally compared to the usage of the gas grid. VDB allows to change the strength of degressive depreciation by a accelerator factor. We stick to the acceleration factor of 1.2 that was decided in the method decision. Based on the previously linear average depreciation costs of 300 M€/year for transport service assets and 65 M€/year for connection service assets, we assumed that the depreciating period for the existing standardized asset value of the transport service assets are depreciated in 22 years and the connection service assets in 26 years.
- We keep the distribution of allowed income over the different kind of connection and transport services similar to the last X-factor decision. Under our baseline and sub-scenario's this is not expected to change significantly. If for example no small sized connections will switch to hydrogen at all, this obviously would lead to different distribution factors of allowed income for a future hydrogen grid. However, investigating this would involve a way more detailed study on the future grid outlook, its costs and allocation justice.
- We base the costs to maintain a hydrogen distribution grid on the KIWA 2018 study [14]. The study states that maintaining and reinvesting in a hydrogen distribution grid will roughly be 5% more expensive than natural gas. Although this study is from 5 years ago already, it is to our knowledge still the most detailed publicly available study to hydrogen distribution grid costs.
- For grid removal costs, 115 €/m pipeline, €7300 per station and €550 per connection are taken into account [15].

- We assumed tariffs will be calculated separately for the methane and hydrogen distribution grid. This means that if part of the grid and its connections are converted from methane to hydrogen, the remaining value of the asset is transferred to the hydrogen distribution grid balance sheet. Also, additional reconversion investments (based on [14]) are included in this sheet. In the results and discussion section we take into account the consequences of the decision whether common or separate tariffs will be used for the methane and hydrogen grid customers.
- We assumed that the capacity of the grid and the offered connections will be roughly similar for users if they change from methane to hydrogen (hydrogen has ~3 times lower volumetric energy density but the velocity can be ~3 times higher as well).

Figure 12 provides an overview of the structure that is used to calculate the grid tariffs. The red boxes represent the input data that was used in the study (scenario input data will be discussed in the next paragraph). The scenario input determines the development of the number of connections and the size of the grid that, based on the existing efficient costs, result in the new efficient costs and allowed income of the distribution grid operator for the specific year. Then, the allowed income is corrected for local charges and grid losses (linearly scaled to the size of the grid) and the costs for grid removals which are also based on the scenario input. The allowed income is distributed over the different connections in the same way as in the current X-factor decision and thereby these result in the new tariffs. The change in tariffs is shown as weighted percentage compared to the baseline year: 2023.

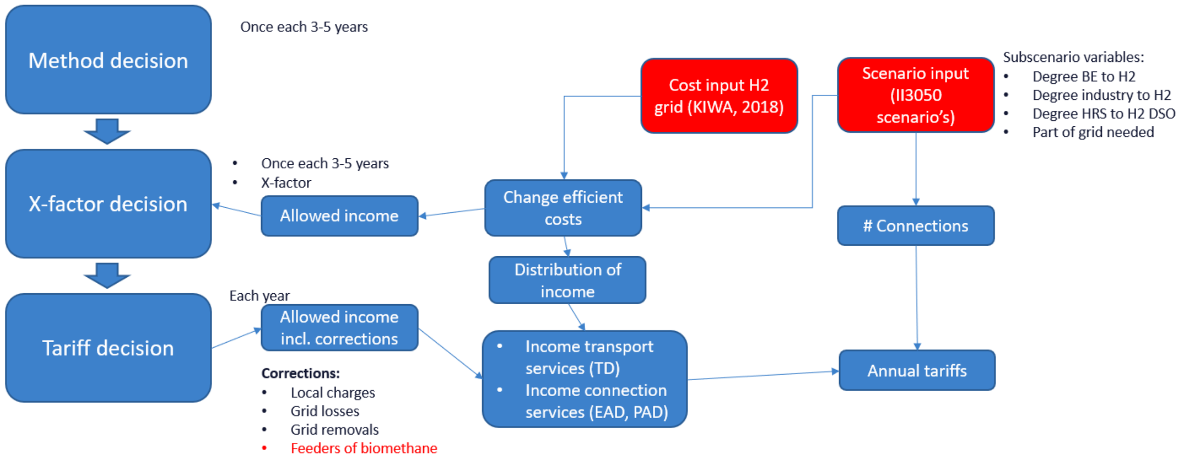

Figure 12 – Overview of grid tariff calculation methodology based on hydrogen grid cost and scenario input

5.2.3 Scenario input assumptions

The number of connections to the methane and hydrogen distribution grid strongly depend on the development of the energy system in the future. To reduce the number of assumptions we have to make ourselves, we decided to stick to the II3050 scenario's [16]. Two of these scenario's assume no use of hydrogen in the built environment towards 2050 ('Decentral initiatives' and 'European integration') and two scenario's assume use of hydrogen in the built environment towards 2050 ('National leadership' and 'International trade'). Because the 'International trade' scenario would let to most use of hydrogen by a wide variety of users, this scenario has been chosen as the baseline scenario. In order to answer the research question, the impact has been investigated if less of a specific user type switch to hydrogen.

In terms of connections, the scenario assumes that the number of households will increase in the Netherlands towards 2050 with 9% by demographic reasons. The other users: the remaining built environment and industry will stay approximately the same. Also, the II3050 International trade scenario assumes that 50% of the 2050 households and built environment connections will be switched to hydrogen. This means that out of the 2023 connections slightly more than 50% of the connections will be switched to hydrogen (since the total number of connections increases towards 2050). In proportion with the final energy consumption development of industry in this scenario, it has been determined that 67% of industrial connections switch to hydrogen. Based on the hydrogen demand by mobility applications and HRS of 2 tonnes/day and 75% utilization rate[7], hydrogen mobility could lead to 395 new connections in 2030, 1299 in 2040 and 1880 in 2050 in this scenario. Figure 13 shows that based on this scenario significant number of connections will be converted to hydrogen from 2030 onwards. After 2040 the speed of conversion increases. From the start to 2050 gradually connections to the gas distribution grid are removed.

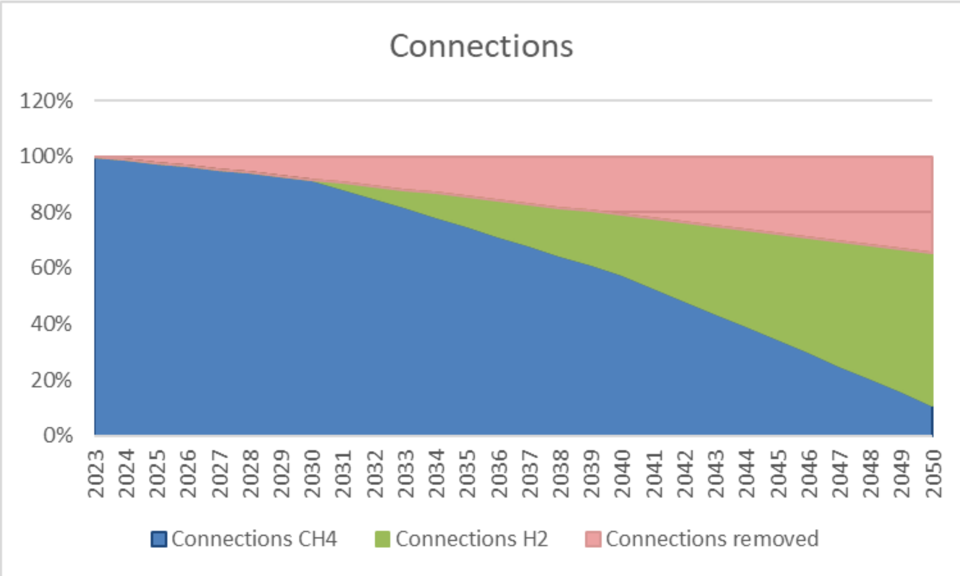

Figure 13 – Overview development of connections to the CH4 and H2 distribution grids towards 2050 in the baseline scenario

The size of the grids in 2050 are based on the geographical representations on supply and demand for both methane and hydrogen that are presented in Chapter 6.3 of the II3050 scenarios [16]. Based on those insights it has been assumed that the CH4 grid size is about 10% of the existing grid and the H2 grid 60%. It is assumed that the methane distribution grid will keep its size until 2030 and thereafter the conversion and removal of different areas of the grid start (see Figure 14).

[7] 2 tonnes/day capacity is the aimed size of future HRS by the EU. 75% utilization is a typical rate for HRS to become profitable.

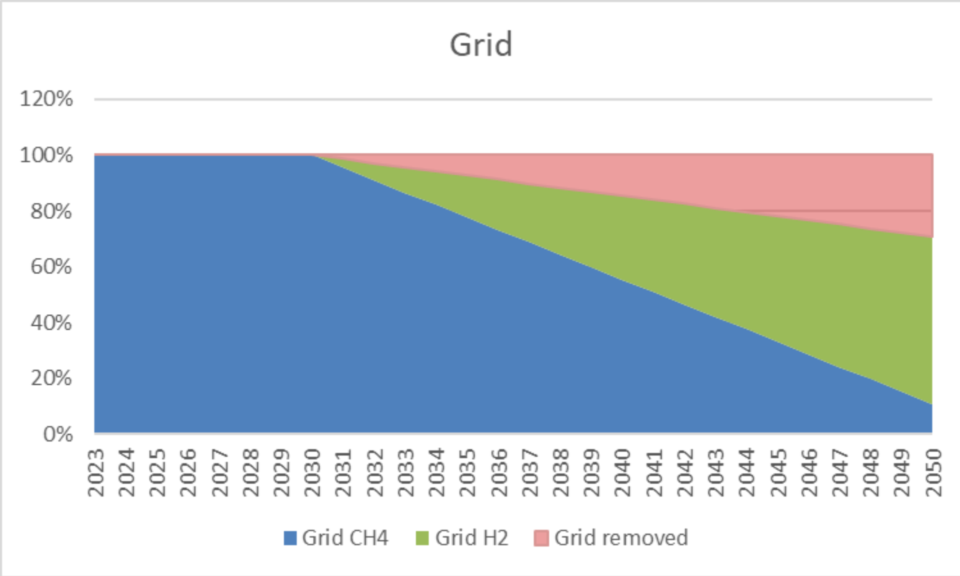

Figure 14 – Overview development grid size for both the CH4 and H2 distribution grids towards 2050 in the baseline scenario

In order to analyse the impact that different type of potential hydrogen end users have on the future grid tariffs, several sub-scenarios are applied:

1. 50% less built environment switches to H2 requiring 50% less grid size.[8] Hence, less small connections are converted to hydrogen and so therefore they have to be removed. Also, a smaller share of the grid is converted to hydrogen and has to be removed as well.
2. 50% less built environment switches to H2 requiring the same grid size. Hence, less small connections switch to hydrogen but still the same grid areas are converted to hydrogen (e.g. more electrification in the regions than expected).
3. 50% less large connections (e.g. industrial) switch to hydrogen.
4. 50% less HRS are connected to the hydrogen distribution grid.

The results of the scenarios are presented in the next section.

5.3 Results & discussion

First we present the results of the baseline and sub-scenario's. Thereafter we highlight other sensitive variables on the future distribution grid tariffs. Finally, the results are discussed by results of previous studies and it is reflected what they mean.

5.3.1 Main results

Roughly spoken, the costs of maintaining the gas distribution grid consist of operational expenses and capital expenses. Operational costs mainly involve personnel costs, for example for inspections and other daily activities of DSO employees. The capital expenses are divided into depreciation costs and costs of capital. Every year new investments are done to replace components that reach their technical end of lifetime. As these new components typically last for a long time, the depreciation periods are typically long as well (often around 40 years). The standardized asset value[9] increases by these new investments and decreases by the depreciation of these assets. If part of the methane grid and its connections are converted to hydrogen, the remaining value of the converted assets and its costs of capital are transferred to the asset balance of the hydrogen distribution grid under our assumptions.

[8] Note that this is just an assumption. In reality this might turn out somewhere in between a proportional decrease in size (sub-scenario 1); or that the same grid size is converted with less connections (sub-scenario 2),
[9] '*Gestandaardiseerde Activa Waarde (GAW)'* in Dutch

If part of the methane grid and/or its connections are removed, there are costs for removal of these connections. If the removed components are not depreciated yet, the remaining value is destroyed since costs have to be paid off but no income is received from this asset anymore. The energy transition leaves the gas distribution grid with a financing issue of how to deal with the remaining value of the gas distribution grid and how to deal with its removal costs. In the baseline results we assumed the current method decision and therefore we neglect potential measures to overcome this issue, except for applying variable declining balance depreciation which is one of the measures applied under the existing method decision already.

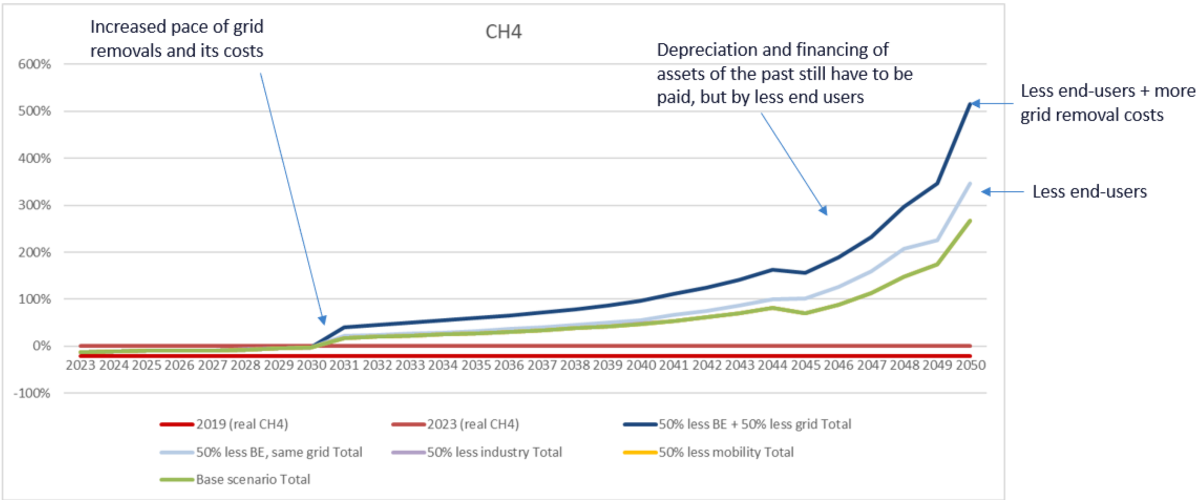

Figure 15 – Methane distribution grid tariff development depended on the degree whether several types of end users switch to hydrogen or not

First, the results of the scenario variables on the methane grid tariffs are presented (see Figure 15). The baseline scenario results are presented by the green line. The red lines indicate the grid tariffs that were seen in 2023 and 2019. The tariffs of 2023 were around 20% higher than in 2019, that was caused to a large extend by the high correction for grid losses due to the high energy prices in 2022. Figure 15 shows that under our scenario and assumptions tariffs will be rising to the same level in 2030 as was seen in 2023, mainly due to the assumed 2% inflation every year. From 2030 onwards, the tariffs rise significantly as from that year, rather than connections, also parts of the gas grid are removed as specific regions switch to electrification. In 2040 the tariffs are doubled compared to the existing tariffs. However, from that year onwards an exponential increase in tariffs is seen as the remaining asset value and its cost of capital are pressing on a significant lower number of connected customers. Small dips in 2045 and 2049 are seen due to the assumptions that the existing grid value is depreciated. If the number of connections will stabilize after 2050 and no further grid removal will take place, then the tariffs would stabilize after 2050 as well (at the 2050 tariff level).

The major trend of these lines is not affected by the type of customers that connect to the hydrogen distribution grid. This is mainly a political manner of how is dealt with the remaining value of the gas distribution grid: should the grid be depreciated faster?; can investments in the existing methane grid be reduced further?; or should the government step in to take (part) of the grid removal costs on its account?

Also, the impact of industrial customers and HRS is limited, as they only represent 4% of the connections and 14% of the allowed income. However, the degree in which the built environment switches to hydrogen can affect the tariffs for methane distribution grid users: 50% of the built environment is a significant extra amount of connections that has to be removed and if an equivalent of the grid has to be removed as well an even stronger increase in tariffs can be expected.

Secondly, the hydrogen distribution grid tariffs. Figure 16 shows that they are significantly less impacted over time. This is due to the assumption that tariffs for the hydrogen and methane connections are separated and the hydrogen grid users are not burned with the costs of stranded assets (we discuss the impact if this is not the case in the discussion section).

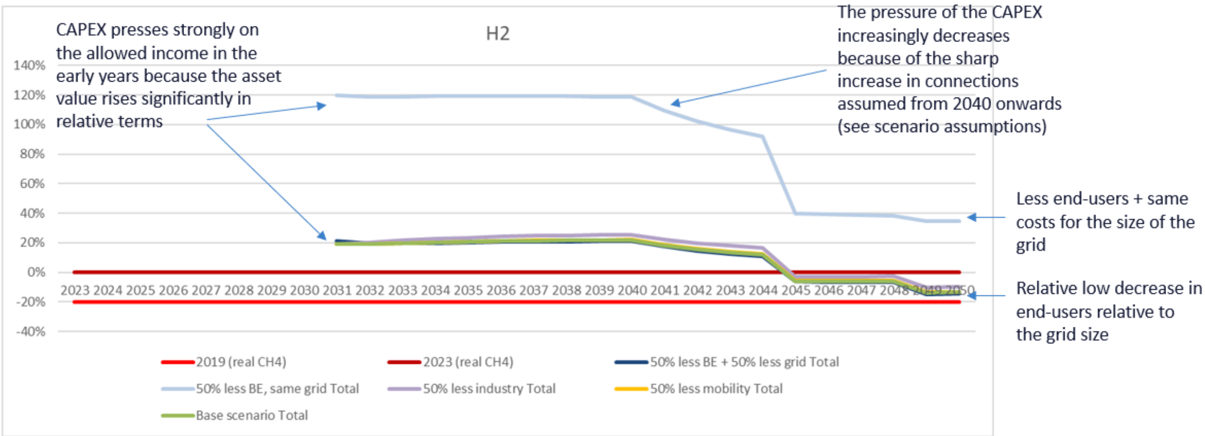

Figure 16 – Hydrogen distribution grid tariff development depended on the degree whether several types of end users switch to hydrogen or not

The development of the hydrogen distribution grid tariffs are characterized by relatively high tariffs in the first decade due to the relative high standardized asset value in the hydrogen distribution grid. This reduces when more customers joining the grid and reduces even further when an increased number of customers joining the grid after 2040 and major parts of the former grid are depreciated. Overall, the hydrogen tariff approximately stays between the tariff levels seen in 2019 and 2023.

The main impact related to the type of connected customers is seen when less built environment connections join the hydrogen grid with the same size as initially assumed. This can be the case, for instance, if there is relatively a large share of customers in the area of the converted hydrogen grid that choose to electrify and disconnect from the gas grid. The impact of the other type of customers (industry and HRS) is, again, less impactful on the projected tariffs as it is a small share of the connections. Figure 17 shows that the sub-scenario with 50% less industry converted to hydrogen has the second largest impact on the tariffs.

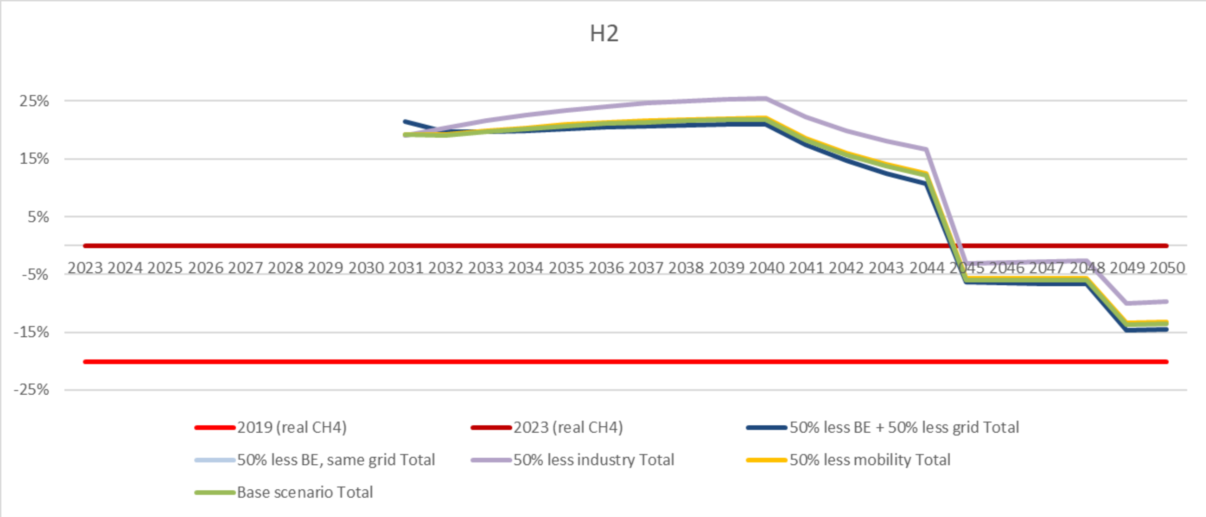

Figure 17 – Figure 16 zoomed in on the impact of industry, HRS and the built environment

5.3.2 Discussion and interpretation of results

Results related to other studies

During the research two studies came across that investigated the future costs and tariffs of the gas distribution grid as well. The first study was performed by Strategy& on behalf of the three largest Dutch DSOs and TenneT [17]. The study mainly focussed on the financial impact of the energy transition on the grid operators. It included the natural gas and electricity distribution infrastructure and electricity transmission infrastructure, but did not take into account potential developments related to conversion of the gas grid towards hydrogen. With regards to the gas distribution infrastructure, it was also concluded that the grid tariffs will rise towards 2050. Although 1.5-2 times compared to 2.5-5 times in our study. The main difference in assumption that seems to cause this difference is that Strategy& used a scenario in which the number of methane connections decreases to 45% of the number of connections in 2020. If we apply the same scenario the methane grid tariffs via our calculation approach would result in a rise of 1.3 times compared to 2023 (including a low WACC/inflation-scenario comparable to the lower bound of Strategy& and moreover assuming degressive depreciation). Strategy& concluded that the number of connections and the WACC are the main impact factors on the distribution gas grid tariffs. Also it provided several suggestions, but mainly focussed on dealing with the large investments in the electricity grid.

The ACM also performed research to investigate the impact of decrease in natural gas usage on the grid tariffs for GTS and the DSOs [13]. The main purpose was to assess if the regulation methodology had to be changed for the method decision on 2022-2026. The study also involved several future scenarios towards 2050 but it is not clear what exact assumptions were made on the number of connections in 2050 so therefore the results are harder to compare. At least conclusions were drawn that: it is expected that a part of the gas grid still will be used by 2050; grid tariffs are expected to rise by a factor 1.4-3.6, mainly due to cost of capital that decrease less fast than the number of connections; connection removal costs are expected in the range of 1.5-3.5 B€ and grid removal costs in the range of 3.5-8.2 B€ based on the scenarios. In our used scenario the total connection removal costs are 1.4 B€ and grid removal costs 4.5 B€. However, note that our scenario considers that a significant part of the grid and its connections is reused for hydrogen (and therefore it is not surprising that grid removal costs are at the lower side of ACM projections).

Overall we conclude that the main outcomes and relations seen do not differ between the two described studies and our work. The main difference is that the studies have different main purposes.

Therefore, our study takes into account the impact of converting part of the grid into hydrogen and its type of end users in greater detail.

Limitations

There are few limitations that should be taken into account when interpreting the results of our study.

The first is the lack of up to date cost data on converting the existing methane distribution grid into hydrogen. Currently, the KIWA study [14] is the most recent extensive public source on this topic. However, since 2018 new insights have been gained in the conversion costs. In discussions with our expert group it was mentioned that some costs will turn out higher than expected during the execution of the KIWA study. Based on the KIWA study and the number of connections to the grid it can be assumed that converting one connection on average would cost €255 per connection. Recent insights are that this might cost €800-1000 per connection. If we take into account €900 conversion costs per connection it would rise the total allowed income until 2050 by 22% and the weighted average hydrogen grid tariff deviation from -14% to 26% of the natural gas grid tariffs in 2023. Another insight of the last years is that sometimes additional new 8 bar hydrogen pipelines have to be constructed if a specific region cannot be connected via a reused pipeline to the transmission grid (simply if the existing 8 bar pipeline still has to be used for methane). The fragmentation of the gas grid for multiple gases makes it slightly less efficient as less gas volumes can be pooled in a single pipeline. These additional costs can be reduced by planning converted grid area's efficiently and making the decision in the area with all types of end users together (such as discussed in HyDelta 1 [10]). However, these costs have not been included in the KIWA study [14] and require a more detailed spatial grid study before they can be taken into account well in studies such as ours.

A second limitation is that we did not include regional feeders of the grid. According to ACM the expected costs of connecting feeders for biomethane are rather limited compared to the total costs related to the gas distribution grid [13]. In the II3050 scenarios the magnitude of decentralized produced hydrogen is also very limited [16]. Therefore, it seems likely that decentral electrolysis will, similar to industry and HRS (that covered just less than 1% of the total connections), will not affect the average grid tariffs significantly. However, the individual tariffs for the local hydrogen feeders could be significant, depending on regional grid characteristics, and if we would assume that similar regulations are applied as for feeders of biomethane. Currently, biomethane feeders are accounted the costs of any grid investments that are required to connect them to the methane distribution grid. Hence, the grid tariffs of these customers highly depend on the degree that (additional) gas boosters or connections between GOS-areas are needed to connect them properly.

The third limitation is that we did not have insight the pace of depreciation of the existing assets. It can be expected that the pace of depreciation will have significant impact on the tariff development over time.

Key discussion points

Besides the answer on the research question, we think the performed research and calculation approach provides some other relevant insights for some key discussion points about gas distribution grid regulation in the coming decades. Three discussion points are highlighted.

1. <u>Who will pay the bill of grid removal costs</u>

The first relevant discussion point is how to deal with gas grid removal costs. Based on the grid removal cost assumptions and the current size of the distribution gas grid[10], removing the whole grid tomorrow would have the following financial impact:

- Removing costs of the grid: 15.5 B€
- Removing costs of connections: 4 B€
- Depreciating all asset value of current transport service assets: 6.6 B€
- Depreciating all asset value of current connection service assets: 1.7 B€

Obviously all these costs do not have to be made because part of the grid stays intact. However, in our scenario (which is the most optimistic II3050 scenario in maintaining the gas distribution grid) still 4.5 B€ of grid removal costs and 1.4 B€ of connection removal costs are made until 2050.[11] The questions rises who should pay the bill of these costs. If the current method decision is continued, future gas grid distribution grid users will pay the bill of this. This is independent if they still use natural gas, or switched to biomethane or renewable hydrogen. Part of this discussion is the expectation that partially lower income households in rental houses will be faced with these costs if landlords see no priority in electrifying their properties. Hence a political discussion point is if the generic tax payer or future gas grid users should be accounted with these costs. Figure 18 shows that if the gas grid removal costs are not accounted on the future users of the (carbon neutral) methane grid, the tariffs would be rising with 80% in 2050 compared to 2023 instead of 268% in the baseline scenario.

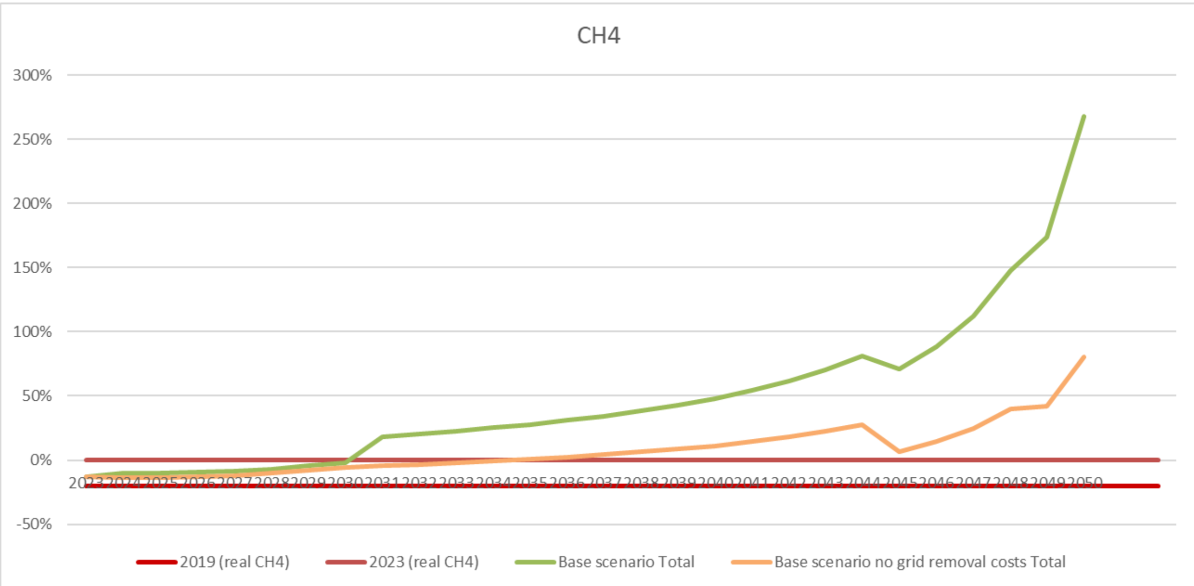

Figure 18 – Impact of grid removal costs on the methane grid tariffs

2. <u>Mutual or separate tariff structure for methane and hydrogen</u>

Another discussion point is whether the tariffs of methane and hydrogen should be separated or not. For example, for distribution of electricity and methane they are clearly separated. Separating the tariffs in this study for methane and hydrogen as different energy carriers was just an assumption, this has not been decided yet. Arguments against separation would be the administrative burden and labour of booking every individual asset to the hydrogen bookkeeping. Another argument is that the increasing costs of grid removals is spread over a larger group of customers. Arguments in favour of

[10] 134.000 km length, 13.000 stations and 7.25 million connections.
[11] We did not take into account that potential remaining value of removed assets has to be depreciated directly.

separating tariffs for hydrogen and methane distribution are that users that invested in conversion towards hydrogen are not burned with the removal costs as well. Secondly, users of biomethane are burdened with the grid conversion costs towards hydrogen. A third argument is that hydrogen is another energy carrier with other physical properties (like methane is different from electricity as well), and therefore other demands for infrastructure (e.g. measuring equipment and inspection requirements). As it is undecided yet how this structure will evolve, we present our resulted tariffs in a combined tariff structure as well in Figure 19. If tariffs are combined a lower increase in tariffs is seen for methane users compared to applying a separate tariff. This is because in our baseline scenario there will still be a significant number of distribution grid users (for both methane and hydrogen together). On the other hand, hydrogen users are going to pay more for their grid connection if a combined tariff is agreed compared to separate tariffs.

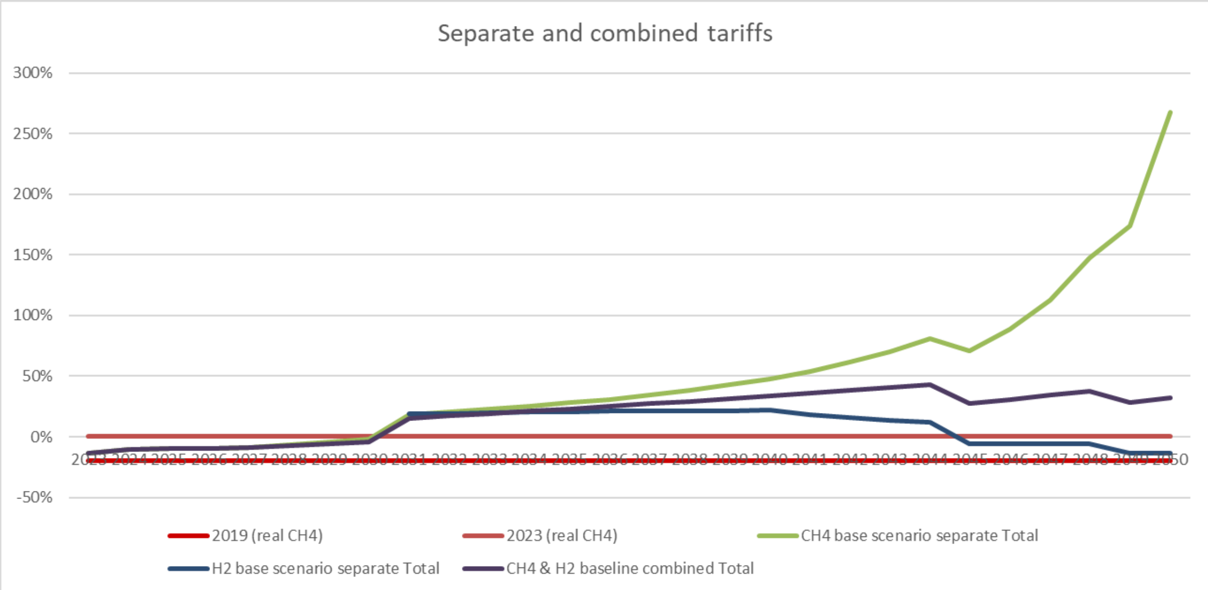

Figure 19 – Difference in tariff development if a combined or separate tariffs are applied for the CH4 and H2 distribution grids

3. <u>Setting the depreciation acceleration factor based on the grid disconnection scenario</u>

In the last method decision of 2022-2026, ACM decided (based on its research to the impact of a declining number of distribution grid customers) to change from a real linear depreciation structure to a nominal degressive (variable declining balance) depreciation structure. The difference between the real and nominal structure is that in the nominal structure there is compensated for inflation in the same year, instead of the following years. Variable declining balance is a degressive depreciation method that increases the depreciation rate in the first years based on a set acceleration factor. Hence, both changes are in place to bring capital costs forward, such that the existing gas grid users are accounted for the costs rather than the future remaining gas grid users. ACM states this approach fits better to the situation of declining number of users, as most of the utilization of the grid (and so the investments) will take place in the early years. ACM chose an acceleration factor of 1.2 based on their scenarios on declining number of connections. In order to set the right acceleration factor a clear vision on the usage of the gas distribution grid is therefore crucial. In order to understand the impact of the acceleration factor better, we applied multiple factors in our scenario (see Figure 20 and Figure 21). Applying an higher acceleration factor especially rises the methane grid tariffs in the early years due to the increased depreciation costs, but lowers tariffs at a later stage (2030-2040, see Figure 20). The impact after 2045 is less significant as we took into account that most of the asset value is depreciated by 2045. Also, applying variable declining balance has no impact on the grid removal costs that are burned on the remaining relatively little number of methane grid users after 2045.

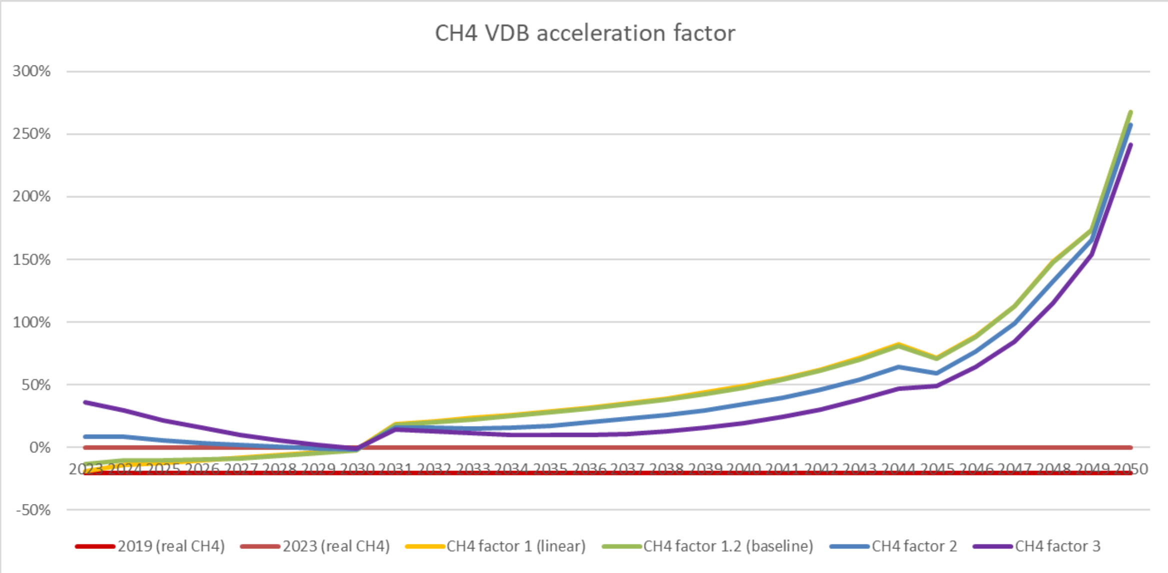

Figure 20 – Impact of acceleration factor used for variable declining balance depreciation on methane tariffs

The application of a higher acceleration factor on the methane distribution grid asset also impacts hydrogen grid tariffs, even if those two tariffs are separated (see Figure 21). This is, because if the grid value is depreciated faster, less value and remaining depreciation costs are transferred and allocated to future hydrogen grid users after the conversion of the grid. Hence, the decision of the acceleration factor has the following impact:

- Potentially increase grid tariffs on the short term and limit tariff increase at a later moment in time for both methane and hydrogen connections.
- It does not impact the burden of grid removal costs on the remaining gas grid users (it can limit potential remaining asset value that is destroyed if those parts of the grid are removed, but due to lack of information our study assumed that all parts of the grid are fully depreciated if removed).

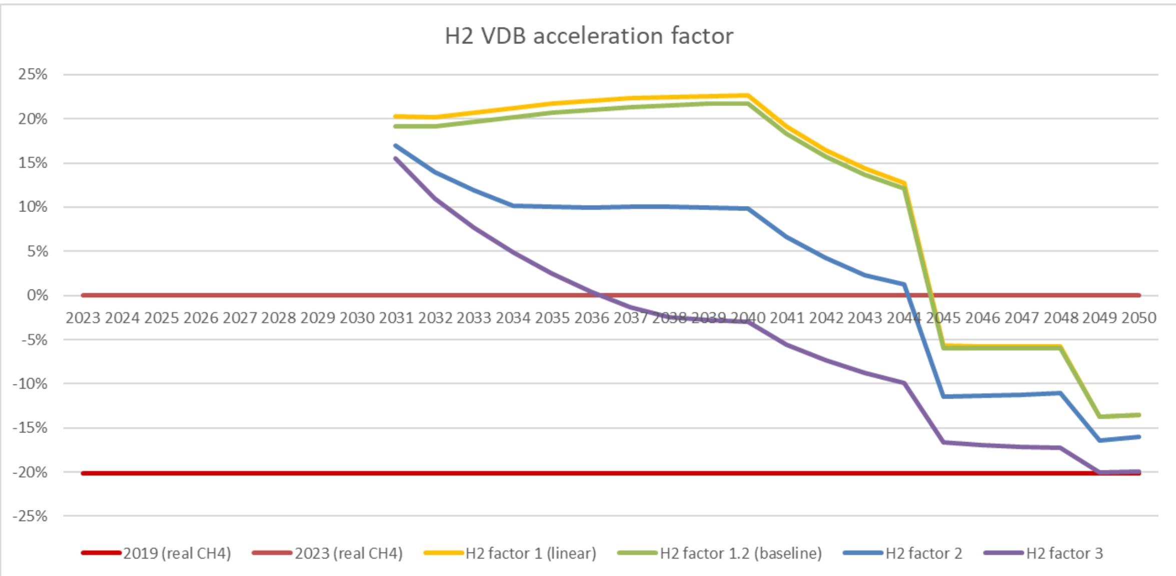

Figure 21 – Impact of VDB acceleration factor (for methane grid assets) on hydrogen distribution grid tariffs

5.4 Conclusions

In this section we answered the following research question:

''What is the impact of different customer combinations on the future hydrogen distribution tariffs?''

In our study we identified some factors that impacted hydrogen distribution grid tariffs significantly:

- The number of connections compared to the size of the converted grid (and thereby also the grid removal costs);
- The costs per connection to convert the grid;
- The way that future hydrogen distribution grids are regulated and financed (e.g. the degree in which hydrogen users are burdened with the costs of removing the gas grid. See next three political issues).

The first factor specifically relates to the impact of different customer combinations that will be connected to future hydrogen distribution grids. Based on the existing method decision and division of allowed income, it is clear that the degree that the built environment switches to hydrogen has a significant impact on the grid tariffs. This is because they represent 98% of the current connections and 85% of the total income of the gas distribution grid. Especially when a relatively large grid area is converted to hydrogen with a relatively low number of connections, the grid tariffs may rise. This could for example be the case if a certain area is determined to be converted to hydrogen, but a lot of customers decide to leave the grid and go full electric: the transport service costs remain the same but are allocated to a lower number of customers. The impact of other type of customers leaving the grid was more limited, because they represent a significantly lower number of connections and share of the total income.

Next to the answer on the research question, three key political issues were raised of which the decisions impact future gas distribution grid tariffs significantly:

1. Who will pay the bill of gas grid removal costs?
2. Should mutual or separate gas distribution tariffs for methane and hydrogen be applied?
3. What acceleration factor in variable declining balance depreciation is applied as long as the future scenario on number of gas distribution grid connections remains unclear?

We advise to decide on these financing and allocation issues timely and collectively. Preferably, this should be done with a clear outlook on the future gas distribution grid in mind (i.e. covered area and number of methane and hydrogen connections).

6 Customer combinations and large scale storage capacity

6.1 Introduction and scope

Gas storage is an essential part of the energy system. Nowadays, and likely also in the future. Currently, among EU members there is gas storage capacity in operation equal to 30% of the total annual gas demand (see Figure 22). For the Netherlands, this is 40%. Note that this is in a system where it is possible to plan the production of gas based on its expected demand. Of course, the demand of gas has a seasonal characteristic (especially the demand of gas to heat buildings). However, it still is clear that even in the fossil demand-driven energy system there is a significant demand for gas storage capacity relative to the annual gas usage. For example to balance portfolios, capture trading value, increase security of supply and to deal with a broad range of uncertainties along the gas supply chain.

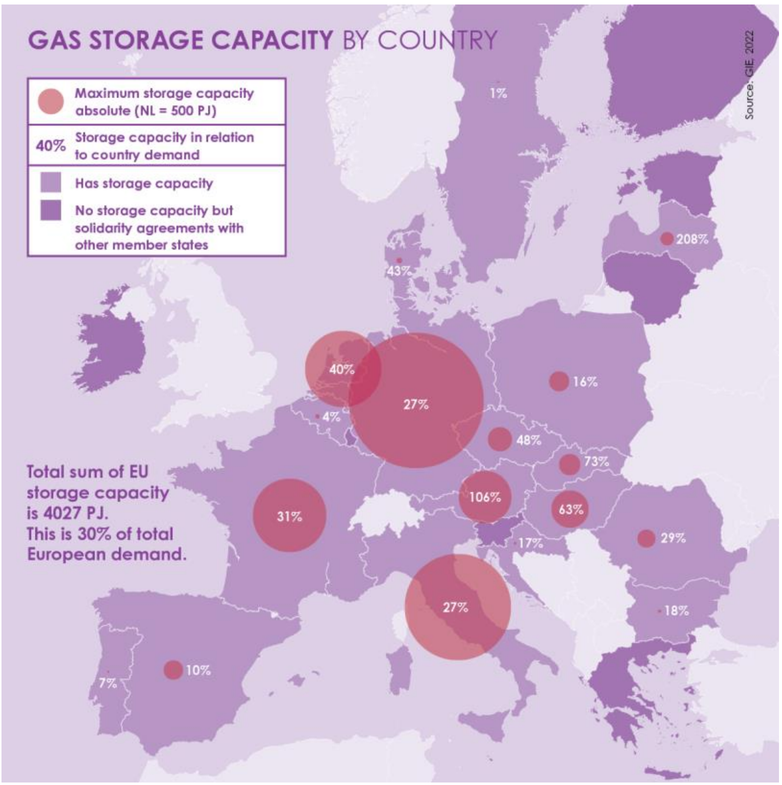

Figure 22 – Overview gas storage capacity by country in the EU [18]

In a future supply-driven renewable energy system similar characteristics are in place that cause demand for gas storage. Moreover, an additional aspect is the intermittency of renewables that the energy system has to deal with. Hence, (renewable) gas storage at least will by expectation stay as important as today. Also, it can be considered that due to uncertainty and security of supply reasons, significantly more gas storage capacity might be demanded than theoretically seems reasonable based on fluctuations in solar and wind generation and demand.

In order to deploy future renewable gas storage capacities and to offer storage services at acceptable costs for end users, it is important to understand how income is earned by selling storage capacity. Based on experience in the storage business of natural gas it is seen that specific combinations of different types of customers can increase the earnings of large scale storage capacity. Therefore, an explorative study is performed to answer the following research question:

''How can different combinations of customers increase the earnings of large scale hydrogen storage capacity?''

In order to obtain insights close to practice, the business models of Dutch large scale natural gas storages are taken as starting point for this analysis. Thereby, changing characteristics of the future Dutch energy system and underground storage of (renewable) hydrogen have been taken into account as well.

6.2 Methodology

The starting point of this study were the business models used for large scale underground natural gas storage in the Netherlands. Two case studies have been chosen as starting point for the analysis: EnergyStock and Gas Storage Bergermeer. EnergyStock is chosen because it is a commercial fast-cycle natural gas storage facility that can 1) deal with short-term fluctuations and 2) has intensions to deploy hydrogen storage in the similar type of salt structures. Gas Storage Bergermeer is chosen because it is the largest commercially available gas storage of Europe, and therefore its service offering is by expectation more specified for seasonal and/or long-term storage needs. Because both fast-cycle and long-term storage characteristics will be relevant for hydrogen in the future, both storage cases are included in this study.

For both case studies the storage service offerings have been investigated. Moreover, scientific literature has been used to specify the generic characteristics behind the offerings. Based on the insights obtained from these activities the commercial gas storage research framework has been established that is described in next subsection. The framework describes the main characteristics of commercial gas storage and therefore provides a starting point to analyse how earnings can be maximized by serving customers with different demands. An interview with a gas storage expert from EnergyStock is undertaken, existing literature is used and calculations are performed to answer the research question and provide indicative examples for the provided insights.

6.2.1. Commercial gas storage framework and key characteristics

For both the EnergyStock and Gas Storage Bergermeer sites, the storage capacity is sold as service and these services are freely accessible for any type of customer that has interest in storage capacity. Broadly spoken, this can be compared with a parking garage: the storage capacity owner sells its capacity (parking spots) for a tariff to customers that want to store their gas (cars). Hence, the storage owner does not purchase and sell gas itself but only sells its capacity as a service.

Figure 23 – For illustrative purposes, a comparison can be made between a parking garage and gas storage facility

In terms of capacity, actually three types of capacity are sold by the storage operator: injection capacity, withdrawal capacity and working gas volume. Injection and withdrawal capacity is the amount of capacity reserved to inject or withdraw gas at a specific moment (in kW or m^3). The working gas volume is the amount of gas that is stored over a specific period (in kWh or m^3/h). Typically, tariffs are established for all three types of capacities, or a bundle of those three.

In terms of conditions, the major characteristics are the following:

- <u>Firm storage vs interruptible storage</u>

Firm storage means that the capacity is reserved with full guarantee for the party that reserved it. This provides full guarantee and flexibility to the customer and therefore relatively a higher price is paid compared to interruptible storage. *Interruptible storage* is the option to book (additional) capacity, but without full guarantee and therefore a lower priority than firm storage capacity.
Most storage services described on the website of EnergyStock can be characterized as firm storage capacity, but via the 'Accelerator service' customers can book additional interruptable storage capacity on short notice. Gas Storage Bergermeer provides a platform where customers can trade ordered capacities, such that one customer can sell its booked but unused firm capacity to another customer who requires additional capacity on short notice.

- No re-nominations vs full re-nominations
  Nominations are the quantities of gas submitted to the transport (and in this case also the storage) operator for a specific hour and at a specific entry/exit point. *Re-nominations* is the option to change the submitted quantities. Storage capacities can be booked with (*full re-nominations*) and without (*no re-nominations*) the option to change the injected or withdrawn quantities of gas.
- Indexed prices vs fixed prices
  Indexed prices means that the tariffs of reserving storage capacity fluctuate over time and *fixed prices* mean that the tariffs are set fixed for a pre-defined period. Both EnergyStock and Gas Storage Bergermeer use indexed prices based on a predefined methodology such that all customers are treated fairly. EnergyStock bases its day to day tariffs on a gas price volatility index, as it is mentioned as one of the key drivers for the value of flexible gas assets. Gas Storage Bergermeer also provides indexed prices based on average summer – winter gas price spreads. Besides the indexed prices, also a fixed price bundle is offered at Gas Storage Bergermeer.

By reservations of capacity at specific moments and for specific periods different types of value can be offered to customers. Gas Storage Bergermeer has around 48 TWh of working gas volume (WGV) capacity in its depleted gas field and is aimed to serve seasonal flexibility and seasonal price spread trading. While the salt cavern storage facility of EnergyStock is smaller (3.6 TWh), but is able to react relatively fast on quarterly fluctuations of injection and withdrawal. Therefore this facility aims to provide short-term flexibility and trade opportunities.

These main characteristics are relevant to understand and interpret the results

6.3 Results & discussion

Based on our analysis three effects are seen in which different customer combinations affect the earnings of future large scale hydrogen storage facilities:

1. The demand for storage in the energy system
2. Plannable injection/withdrawal capacity needs without re-nominations
3. Complementary profiles that maximize the reserved firm storage capacity

6.3.1. The demand for storage in the energy system

As discussed in 6.2.1 both analysed Dutch natural gas storage sites apply indexed tariffs for reservations of capacity. This makes sense as the value of storage capacity for traders changes by the volatility and periodic spreads of gas prices. Moreover, there are moments in which more customers demand more flexibility than other moments, for example because there is more uncertainty (e.g. in winter energy suppliers might reserve more withdrawal capacity as the gas demand of the built environment depends to a larger extend on outside temperatures). The degree in which within day or seasonal flexibility is need highly depends on the type of customers in the energy system (see Figure 24). The more flexibility is required, the higher the earnings of the available storage capacity by the storage operators. In the next paragraphs we will illustrate how this works for both natural gas and hydrogen gas storage.

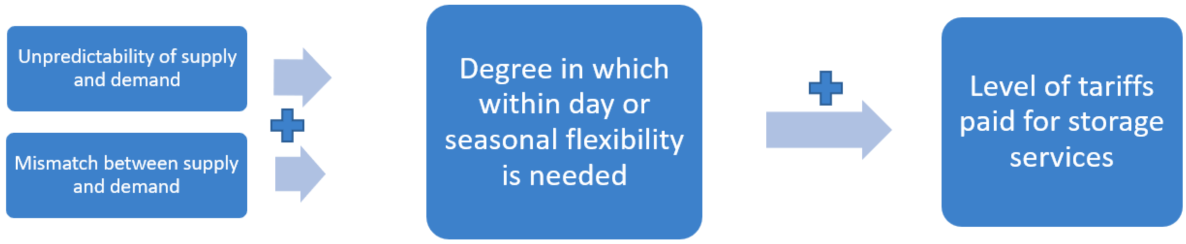

Figure 24 – Conceptual framework of how supply and demand characteristics in the energy system impact the tariffs of available storage capacity

Natural gas storage

Currently the main type of customers of gas storages are energy suppliers, energy traders, power generators, large industrial off takers and the gas transmission operator. Typically a baseload of storage capacity is relevant for each actor depending on energy and its prices, in order to guarantee security of supply for example to deal with maintenance, defects and disruptions in gas prices.

Moreover, there are some specific unpredictable supply and demand characteristics that cause relatively a lot of demand for natural gas storage capacity. This are the seasonal and within day unpredictability of demand for natural gas in the built environment; and the seasonal and within day unpredictability of demand for natural gas by power plants. The first is mainly caused by unpredictability in outside temperatures during winter: if the next day, week or month becomes more cold than expected, energy suppliers still have to guarantee supply. The same occurs for natural gas power plants: if there is more or less solar and wind electricity generated than expected, natural gas power plants could adapt their production schedule. To do so, they need less or more natural gas than initially nominated.

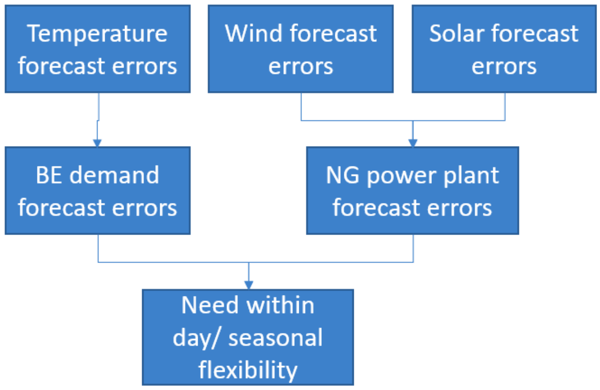

Figure 25 – Current need for natural gas storage due to weather unpredictability and forecast errors

Hydrogen gas storage

For hydrogen gas storage a similar need for flexibility might evolve like natural gas. Especially in the early phase of hydrogen developments demand for hydrogen will mainly be industrial processes. These are typically stable and therefore flexibility demanded by storage by these type of off takers will be mainly for security of supply reasons. A key factor determining flexibility needs in the early phases of hydrogen development is the degree in which wind and/or solar based electrolysis will be used for hydrogen supply (rather than for example imported hydrogen carriers and blue hydrogen). The output from wind and/or solar based electrolysis could be predicted as full load, but can turn out to be zero if it will be more cloudy or less windy than forecasted. In this case a similar level of flexible capacity should be in place to deal with this disruption in supply. This could for example be withdrawal capacity from a hydrogen gas storage facility. Hence, the level of established wind and/or solar based electrolysis capacity is one of the key factors for hydrogen storage needs.

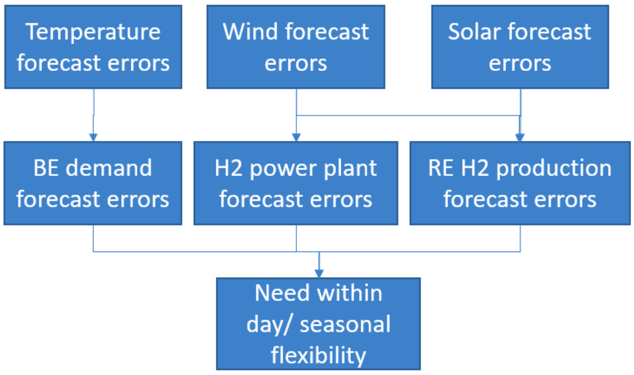

Figure 26 – Potential need for hydrogen gas storage due to weather unpredictability and forecast errors

In a later phase the demand for hydrogen storage in the energy system will be determined by two other factors: 1) the degree in which the built environment will be heated by hydrogen; and 2) the degree in which dispatchable power is produced by hydrogen power plants. As renewable electrolysers and hydrogen power plants are affected in the opposite way by wind and solar forecast errors, the flexibility needs double. For example, in case it turns out less windy and or less sunny than forecasted, withdrawal capacity had to be booked instead of the initially booked injection capacity. Hence, independent which exact parties will account themselves for this uncertainty, there should be reserved storage capacity to deal with these forecast errors to deliver the contracted energy supply.

Short and long term variability

The unpredictability in the examples of previous paragraphs could happen on hourly, daily, weekly, monthly and seasonal basis. However, the longer the period the less extreme the unpredictability. For example, for an hour or day the output of solar and wind based electrolysis could be zero instead of full load. Also, the demand of the built environment could be approximately twice as big if it turns out to be 10 degrees Celsius instead of 14. However, on a yearly basis the variability is less extreme: from 2010-2019 the weather impact on the gas demand for heating never fluctuated more than 21% compared to the average; for solar output it never fluctuated more than 10% of the average output; and onshore wind output never fluctuated more than 12% based on the wind speed input. Hence, the short term variability by expectation can lead to larger deviations from its predicted value than the seasonal variability.

Summary

Any type of customer demands storage for security of supply reasons. There are three (potential) hydrogen stakeholders that can increase the demand for hydrogen storage in the Dutch energy system significantly: electrolysers based on variable renewable electricity, hydrogen power plants and the built environment. Out of these three categories the electrolysers are likely to be established the earliest. The more hydrogen is supplied via electrolysis compared to dispatchable alternatives (e.g. reforming or imports) in the energy system, the more customers are likely to compete for the available storage capacity established by that time.

6.3.2. Plannable injection and withdrawal capacity needs without the option for re-nominations

As introduced in section 6.2.1, there is a difference between storage capacity reservations with and without the option for re-nominations. If hypothetically the full injection capacity would be booked with the option to re-nominate, storage operators cannot sell additional injection capacity under the full guarantee that this capacity is available. In other words, no more than the available capacity can be sold for both the injection and withdrawal capacity (see Figure 28).

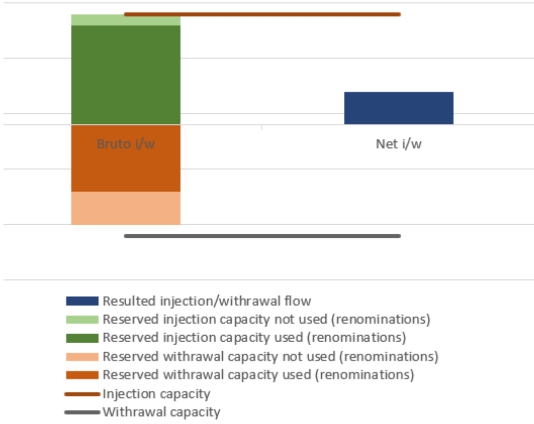

Figure 28 – Indicative example of injection and withdrawal capacity reserved with renominations (no more capacity can be sold than available)

If injection or withdrawal capacity is sold without the option to re-nominate, the customers have agreed that they are going to use the reserved capacity anyways. If, for the same timeframe, both injection and withdrawal capacity is reserved without the option to renominate, they can be distracted from each other since the net required injection/withdrawal capacity will be lower than the reserved capacities. As long as the net injection/withdrawal rate falls within the capacity of the storage facility, reservations without re-nomination can be accepted. Figure 27 illustrates an indicative example of such a situation: there is sold more injection capacity than available. However, since there is sold withdrawal capacity as well, the net injection rate does not exceed the maximum injection capacity.

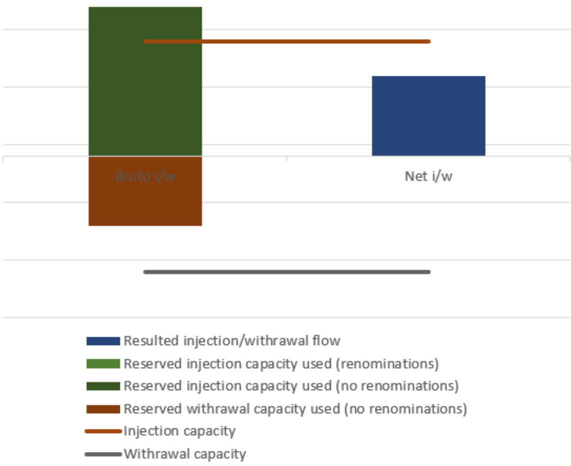

Figure 27 – Indicative example if injection and withdrawal capacity is reserved without the option to re-nominate (more capacity can be sold

In reality the reserved capacities would typically be a mix of reservations with and without the option for re-nomination. Storage customers can make their own optimizations as well by reserving partially with and without the option to re-nominate, as reservations without the option for re-nomination have lower prices. To illustrate indicatively, a third example is shown in Figure 29.

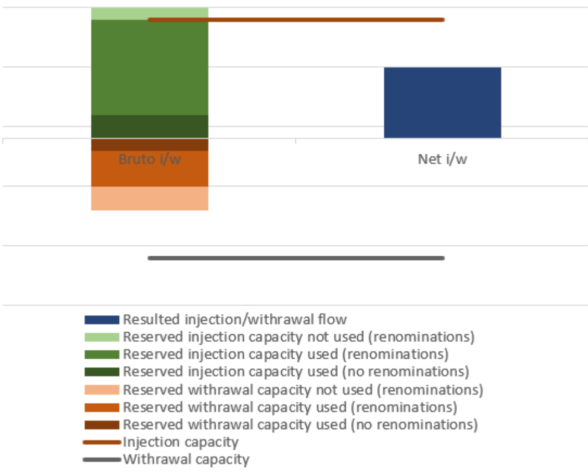

Figure 29 – Indicative example of a mix in capacity reservations with and without the option to re-nominate. Note: this is a new example and not a combination of the numbers assumed in figure 27 and 28

By different customers having injection and withdrawal requests at the same timeframe, the storage operator can save operational costs (such as energy costs to operate the facility). Moreover, the more injection and withdrawal requests without the option to re-nominate occur at the same moment, the more capacity can be sold by the storage operator. Therefore, having such combinations of customer requests can increase the earnings of the storage operator.

6.3.3. Maximization of sold (firm) storage capacity by complementary customer profiles

The previous chapter focussed on the way injection and withdrawal capacity is reserved and sold. The third effect described in this chapter focusses on the reservations and usage of working gas volume (WGV) capacity. Given that Gas Storage Bergermeer has 48 TWh times 8760 hours per year of WGV capacity to sell. However, as it is a facility used for strategic reserves and seasonal storage typically the highest quantities of working gas volume are sold in July until December, when the filling rate of the storage facility is the highest (see Figure 30).[12] For EnergyStock a similar trend is seen, even though the number of filling and withdrawal cycles is significantly higher (see Figure 31). This trend clearly aligns with the seasonal gas demand for heating applications.

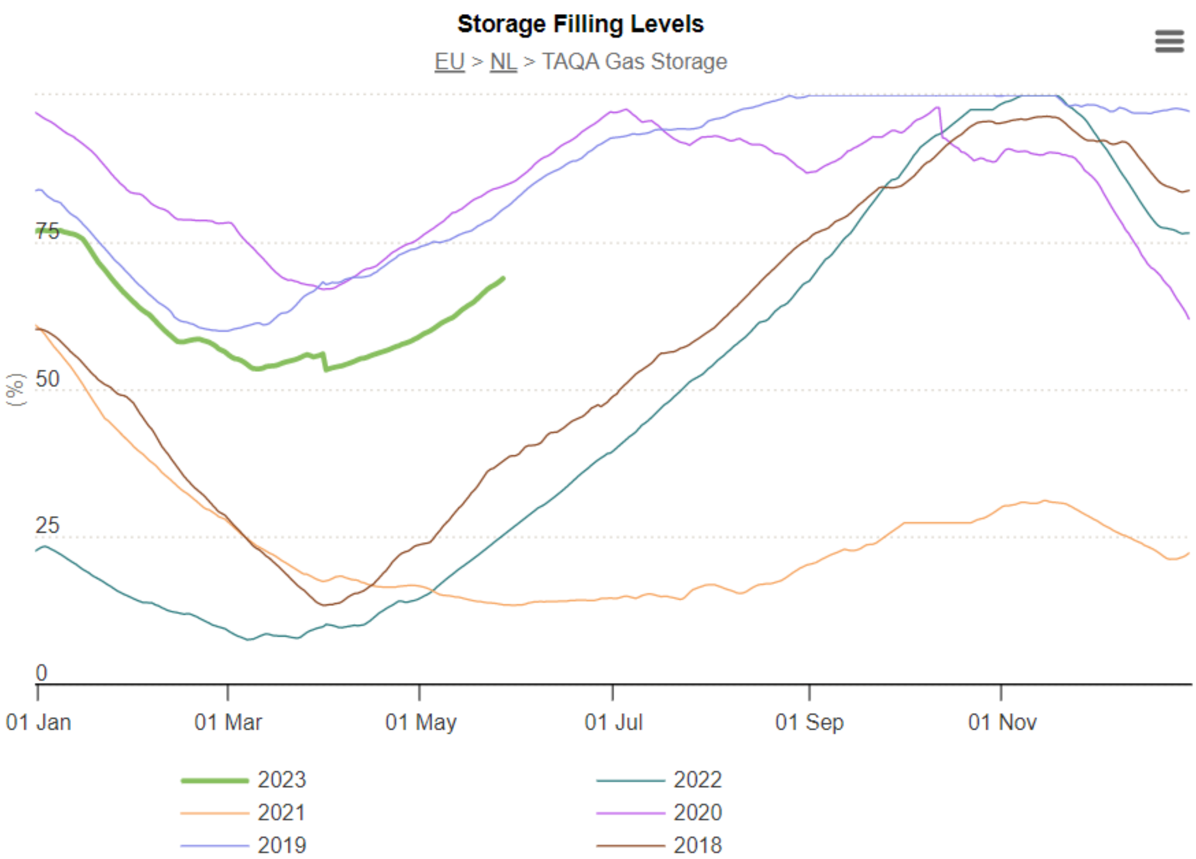

Figure 30 – Historical storage filling levels of Gas Storage Bergermeer. Retrieved from [19].

A second observation is that the average filling rate differs significantly over the years. For example, in the time period of 2011 and 2022 both storage facilities have years with average annual filling rates above 80% and below 30%. If this represents the sold firm capacity this means that storage facilities have significant differences in turnover over the years. The differences in average annual filling rates can have a diversity of reasons: developments in natural gas market prices, geopolitical circumstances (e.g. corona, Ukraine crisis) or cold/warm winters. For example, highly filled gas storages followed by

[12] The filling rate (actually used storage) obviously differs from the sold firm capacity. Unfortunately no data is publicly available on this.

a relatively warm winter are resulting in a typically high filling rate over the years. The same counts for unstable years, in which higher safety stocks are demanded.

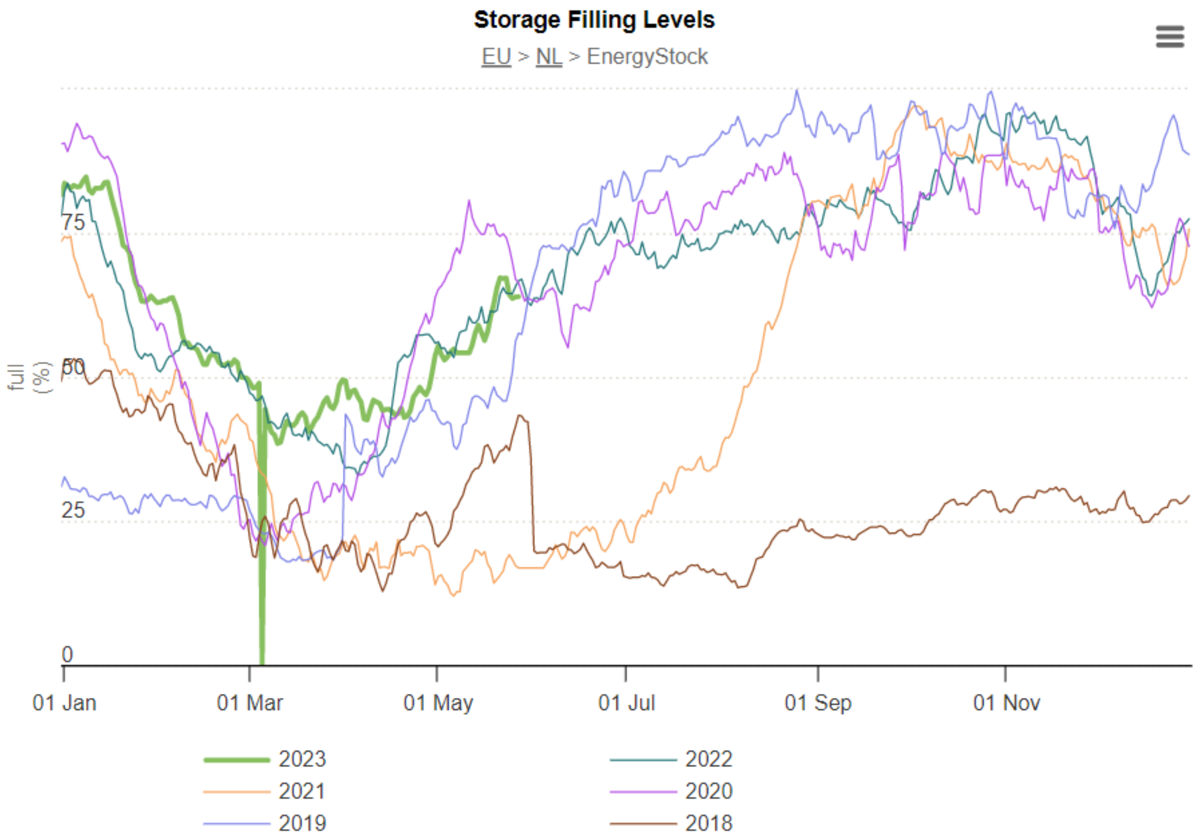

Figure 31 – Historical storage filling levels of EnergyStock. Retrieved from [19].

Although we do not have information about the actual quantities of firm storage capacity reservations booked, we clearly see that the existing storage capacity for natural gas has its main safety stock ready at the end of the summer (October/November) in order to deal with the seasonal and uncertain demand in the winter. This leads to a clear demand for WGV capacity in the autumn and less in the spring, which means that under typical conditions the storage operator is able to sell a lot capacity in one half of the year and less in the other half.

Figure 32 shows generic storage patterns based on generic offshore wind and onshore solar supply patterns, and demand in the built environment. If we assume a stable supply and the demand for heat in the built environment, it shows that at the peak moment 33% of the annual demand is in storage.[13] For wind and solar these peaks are less strong (26% and 12% respectively). Thereby, potentially solar based hydrogen supply[14] requires safety stock at the same period as the built environment while offshore wind based hydrogen typically requires it safety stock in the reversible period.

[13] Which is, accidentally or not, quite similar to the 30% and 40% of existing natural gas storage capacity in the EU and the Netherlands respectively.
[14] Or: hydrogen demand by potential hydrogen gas power plants that would run especially when the sun does not shine.

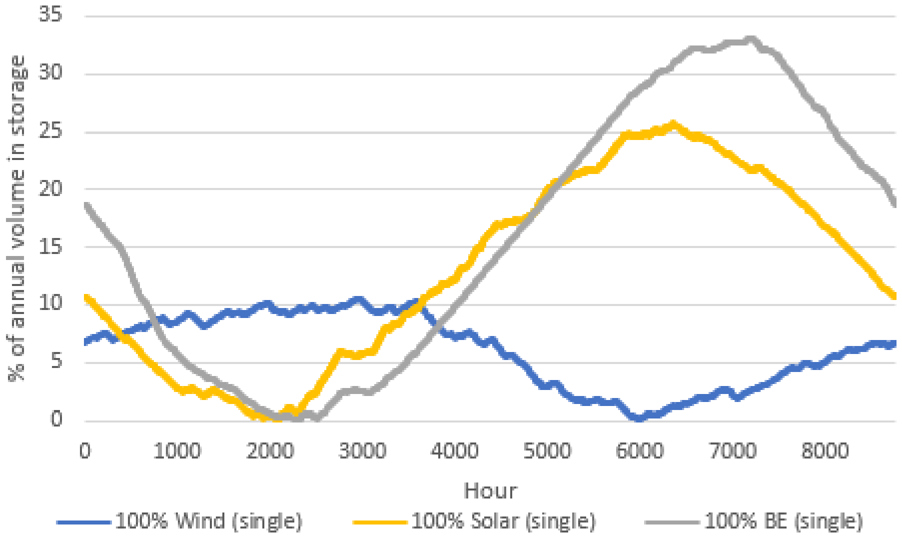

Figure 32 – Generic storage patterns based on offshore wind, onshore solar and heating demand in the built environment

Based on to what type of balancing, safety stock and seasonal spread trading is required by the mix of customers for future hydrogen storage, the WGV capacities that are sold by the storage operator can be increased. This is the case if the peak of storage demand and supply/demand uncertainty is spread more over the year instead of being present in one season or period. We show two simple illustrations to explain.

The first example is based on the complementarity between the solar and wind supply profile.[15] If a future hydrogen storage facility would serve storage for solar and wind based hydrogen supply for a stable offtake (e.g. large industrial offtake), Figure 33 illustrates that applying a 70/30 ratio of demand being fulfilled by wind and solar supply respectively leads to a relative spread of potential storage capacity reservations over the year. Thereby, the likely usage of storage also significantly decreases if the seasonal supply of both types of supply is combined in one storage (4% of annual supply compared to 8% of supply if both are stored separately).

[15] Or, again: demand profile based on a power plant that provides back-up electricity for solar and/or wind electricity.

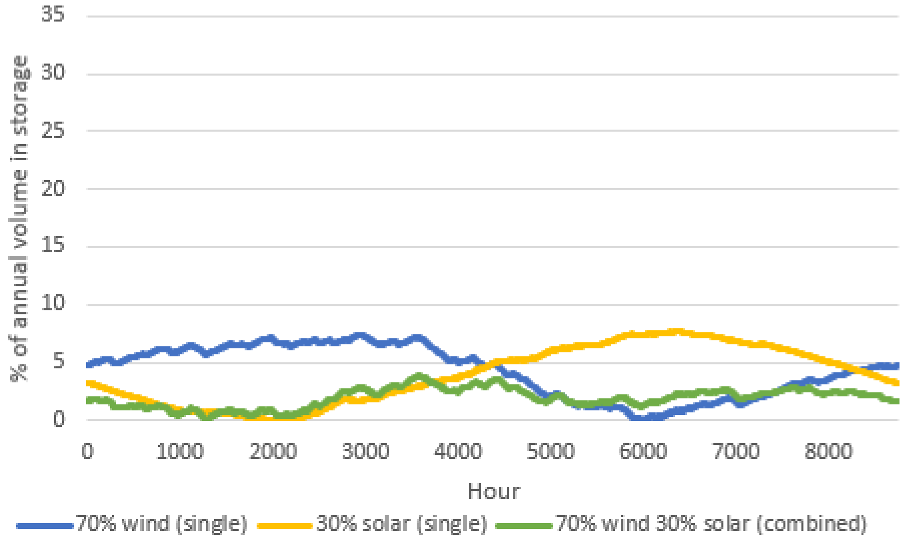

Figure 33 – Illustration of the complementary seasonal profiles of solar and wind, in case if 70% of wind and 30% of solar supply are combined to serve 100% of stable demand

A second example is when hydrogen supply by offshore wind is supplying partially the built environment and partially offtakes with a stable seasonal pattern. As offshore wind typically supplies more hydrogen during winter and so do the demands for heat in the built environment. Since the seasonality in the demand of the built environment is significantly larger than the seasonality of wind production, the complementarity is optimal if about 25% of production is served to the built environment and the remaining 75% to offtakers demanding for stable supply.

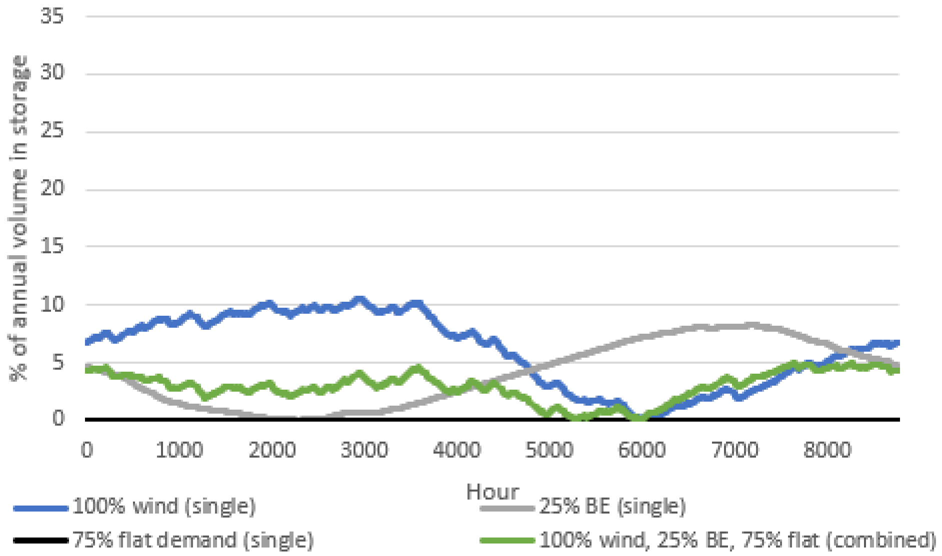

Figure 34 – Illustration of the complementary seasonal profiles of wind and the built

Obviously, the storage operator itself has limited influence in which mix of customers it will attract. Moreover, practical experiences show that although a trend in storage filling rates is seen, the filling rates and storage need differ from year to year based on a lot of external factors. Still, it remains viable that the characteristics of the flexibility and/or storage need will be based on the mix of future hydrogen suppliers and offtakers. More explicit, this means the mix of hydrogen supply by solar and wind, and degree of usage of hydrogen for heating in the built environment, stable offtakers and dispatchable power plants.

It turned out that certain mixes could lead to more equally spread reservations of WGV capacity along the year and therefore increasing the earnings of the storage facility operator. Another aspect of more complementary profiles and uncertainty spreads is that the uncertainty of in different customer profiles are more likely to be pooled. For example by re-selling reserved firm storage capacities to other customers as interruptible storage capacity (for example if it turned out to be a warm winter but also a less windy spring, firm storage capacity reserved for electrolysers running on offshore wind can be sold to customers mainly serving the built environment). Therefore, combining these customer profiles is not only relevant for storage operators, but also in the portfolio management of energy suppliers and the design of the future energy system as a whole.

6.4 Conclusions

Based on the analysis three effects were found and described that answer the research question:

''How can different combinations of customers increase the earnings of large scale hydrogen storage capacity?''

The three ways how different combinations of customers can increase the earnings of operating large scale hydrogen storage capacity are the following:

7 The demand for storage in the energy system relative to the available capacity, that will increase the tariffs asked for storage capacity reservations.
8 A similarity in injection and withdrawal capacity needs without re-nominations, by which more injection and withdrawal capacity can be sold and operational costs can be saved.
9 Complementary profiles that maximize the reserved and utilized WGV capacity during the year.

The insights can be used by future hydrogen storage operators and energy suppliers to optimize their customer portfolios. Although, it is recognized that the degree in which the effects occur are also mainly dependent on the design of the future energy system and the types of hydrogen supply and demand that will be established. Therefore, the insights are also very suitable in evaluating the impact of potential hydrogen storage customer combinations can have on the storage costs. In the end the storage costs will be part of the bill that customers will pay for the hydrogen.

Lastly, it should be noted that the research focussed on the impact of customer combinations. Meanwhile, it has been noticed that other factors are also impacting the earnings of storage operators. Examples are the gas market price volatility, perceived uncertainty and geopolitical/economic stress. Although such factors were not the main focus of research, it is clear that they are of high importance for the earnings storage operators and are typically also highly uncertain.

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