HyDelta 2

WP4 – Regional blending in the regional transmission (40 bar) pipelines to overcome congestion in the electricity grid

D4.3 – Report on the main policy implications of the potential of hydrogen for regional electricity grid congestion mitigation

Status: complete

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Executive summary

As a short supplement, this deliverable serves as a policy recommendation document in regards to the results derived from deliverable D4.1 and D4.2. Both deliverables investigated solutions for mitigating the prevalent and ongoing electricity grid congestion in the Netherlands from a regional perspective via the implementation of PtG systems (e.g., via electrolyzers) and other flexibility providing options such as utility scale batteries and curtailment techniques. It was shown that local PtG investments and subsequent hydrogen blending can be a first step towards local integration of electricity and gas systems. These investments can help by offering a solution for local e-grid congestion problems; enhancing the profitability of RES investments; and improving local security of supply conditions. They can also act as a stepping stone to synergistically serve an increasing number of end users besides local industry (e.g. mobility and the built environment); and may act as a dominant enabler of a decisive decarbonisation trend in the entire relevant area.

This can be done by:

1. Authorities providing as clear information as possible on local supply-side congestion perspectives.
2. That reliable information is provided if local investment in a hydrogen blend really involves a step towards full decarbonisation of natural gas use in decentral industries: one has to be sure that ultimately one will be able to implement pure green hydrogen via increasing blending percentages.
3. Reducing the regulatory uncertainty of if and when the gas transmission service operator (TSO) and/or distribution service operators (DSOs) are legally allowed and/or capable to facilitate a 'pure' hydrogen transport connection to the gas grid, or, in the preceding stages, to apply blends of hydrogen in the grid.

Results also clearly indicated that a **mix of flexibility solutions** can cost-effectively reduce electricity grid reinforcement needs and therefore societal costs, but only if cost-benefit analyses are **systematically implemented** and new legislation and regulatory measures are introduced supporting that the incentives to get to the optimal solution are implemented. These alternative options require alignment of stakeholders interests and a supportive legislative and regulatory framework. Hence some main recommendations can be given to policy makers:

- Identification of which specific legislations and regulatory measures would be required to provide right incentives for solar park and wind farm operators, regional grid operators, and electrolyser and battery operators such that maximum green energy benefits are delivered against lowest overall costs.
- Based on systematic regional prognoses for new decentral renewable capacities and electricity demand, regions should be identified where electricity supply will exceed demand regularly. This information can be used to identify the regions in which decentral hydrogen production is the most promising. This information should be made public so that new investors in solar (and wind) capacity and the distribution grid operator can together investigate several options to integrate the additional renewable energy in the system.

Given the seriousness of the domestic e-grid congestion issues such developments are urgently needed (both for the distribution and transmission e-grid); in fact not having them in place can be seen as a serious obstacle for green hydrogen and battery investment, and a stimulus for growing undue e-grid congestion.

Samenvatting

Als korte aanvulling dient dit document als beleidsaanbevelingsdocument met betrekking tot de resultaten die zijn afgeleid van de producten D4.1 en D4.2. Beide deliverables onderzochten oplossingen voor het verminderen van de heersende en aanhoudende congestie van het elektriciteitsnet in Nederland vanuit een regionaal perspectief door de implementatie van PtG-systemen (bijv. Er werd aangetoond dat lokale PtG-investeringen en daaropvolgende bijmenging van waterstof een eerste stap kunnen zijn naar lokale integratie van elektriciteits- en gassystemen. Deze investeringen kunnen helpen door een oplossing te bieden voor lokale congestieproblemen met e-grids; verbetering van de winstgevendheid van RES-investeringen; en verbetering van de lokale voorzieningszekerheid. Ze kunnen ook dienen als springplank om naast de lokale industrie (bijvoorbeeld mobiliteit en gebouwde omgeving) steeds meer eindgebruikers synergetisch te bedienen; en kan fungeren als een dominante aanjager van een beslissende decarbonisatie-trend in het hele relevante gebied.

Dit kan door:

1. Autoriteiten die zo duidelijk mogelijke informatie verstrekken over de vooruitzichten op lokale congestie aan de aanbodzijde.
2. Dat er betrouwbare informatie komt als lokale investering in een waterstofblend echt een stap is naar volledige decarbonisatie van het aardgasgebruik in decentrale industrieën: men moet er zeker van zijn dat men uiteindelijk via toenemende bijmengpercentages zuivere groene waterstof kan implementeren.
3. Verminderen van de reguleringsonzekerheid of en wanneer de gas-TSO en/of DSO's wettelijk zijn toegestaan en/of in staat zijn om een 'zuivere' waterstoftransportaansluiting op het gasnet te faciliteren, dan wel in de voorgaande fasen waterstofmengsels toe te passen in het rooster.

De resultaten toonden ook duidelijk aan dat een mix van flexibiliteitsoplossingen op kosteneffectieve wijze de behoefte aan versterking van het elektriciteitsnet en dus de maatschappelijke kosten kan verminderen, maar alleen als kosten-batenanalyses systematisch worden uitgevoerd en nieuwe wet- en regelgevende maatregelen worden ingevoerd ter ondersteuning van de stimulansen om de optimale oplossing worden geïmplementeerd. Deze alternatieve opties vereisen afstemming van de belangen van de belanghebbenden en een ondersteunend wet- en regelgevingskader. Daarom kunnen enkele belangrijke aanbevelingen worden gedaan aan beleidsmakers:

- Identificatie van welke specifieke wet- en regelgevende maatregelen nodig zijn om de juiste prikkels te bieden aan exploitanten van zonneparken en windmolenparken, regionale netbeheerders en exploitanten van elektrolysers en batterijen, zodat maximale voordelen van groene energie worden geleverd tegen de laagste totale kosten.
- Op basis van systematische regionale prognoses voor nieuwe decentrale duurzame capaciteiten en elektriciteitsvraag moeten regio's worden geïdentificeerd waar het elektriciteitsaanbod de vraag regelmatig zal overtreffen. Met deze informatie kan worden bepaald in welke regio's decentrale waterstofproductie het meest kansrijk is. Deze informatie moet openbaar worden gemaakt, zodat nieuwe investeerders in zonne- (en wind)capaciteit en de distributienetbeheerder samen verschillende opties kunnen onderzoeken om de extra hernieuwbare energie in het systeem te integreren.

Gezien de ernst van de congestieproblemen van het binnenlandse e-net zijn dergelijke ontwikkelingen dringend nodig (zowel voor het e-net voor distributie als voor transmissie); het feit dat ze er niet zijn,

kan zelfs worden gezien als een ernstig obstakel voor investeringen in groene waterstof en batterijen, en een stimulans voor toenemende overmatige congestie op het elektriciteitsnet.

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1. Introduction

In order to move towards a renewable energy system in the Netherlands, an increasing capacity of renewables has to be connected to the electricity grid. This now already causes very serious e-grid congestion issues, especially in the distribution grid. Reinforcement of the e-grid: can be very expensive if technologically and/or legally feasible at all, costs considerable time for various reasons; and requires an electrotechnical workforce that often is not or scarcely available. So, Dutch electricity distribution service operators (DSOs) are facing growing congestion problems in providing grid connections in time for new renewable energy capacities. It is in fact likely that in the Netherlands e-grid congestion will be a reality and growing concern for at least the coming decade. This results in sometimes long connection waiting times for solar and wind farms (supply-side congestion) and similar adverse access conditions for the energy end-users (demand-side congestion). It also means that in the near future new solar and wind farms will not be able to deliver electricity to the grid at all times. The figures below illustrate the current (2023) state of supply- and demand-side congestion in the Netherlands.

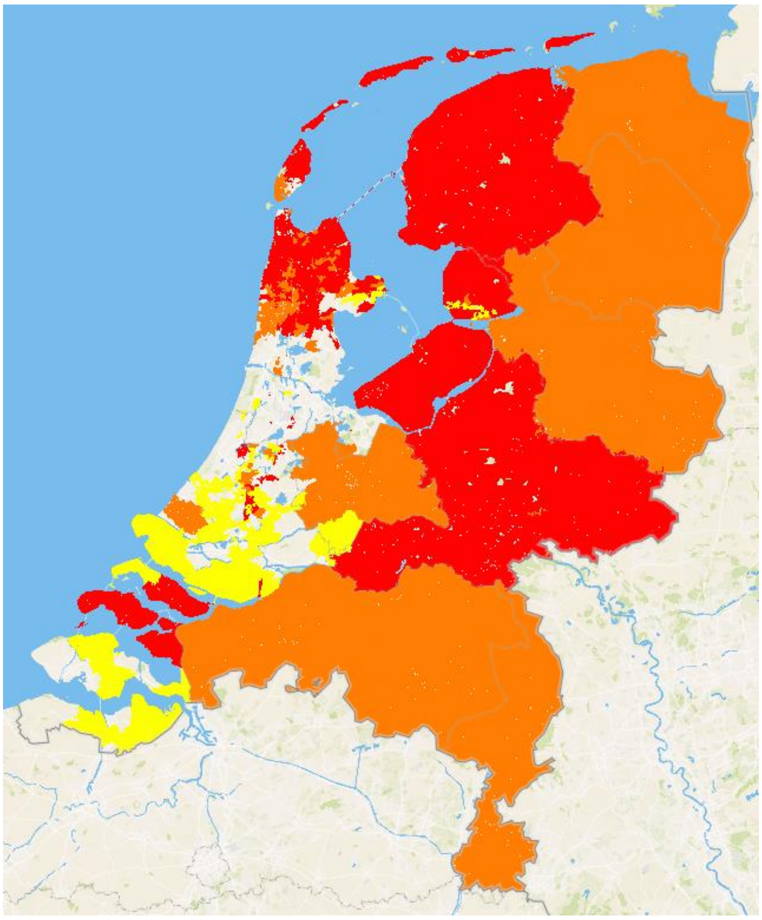


Figure 1: State of supply-side congestion in the Netherlands. Date: 30-03-2023 [1]

At the same time, there are a number of decentral industrial clusters in the Netherlands – the focus of this study – also called cluster 6 industries (responsible for some 14% of national CO2 emissions) that are quite dependent for their decarbonisation on access to green energy (and green molecules in particular) and related energy and feedstock transport infrastructure (e.g. for CO2, heat, electricity and gases). However, especially for these industries the right transport connections for that, such as the hydrogen backbone or heat- and CO2-networks, are often not in proximity, not easily accessible, or not within reach at all. Stakeholder information and literature on this suggests that there sometimes is great potential for these decentralised industries and industry clusters to switch to (blends of) hydrogen sometimes even at relatively short notice, especially if no other efficient decarbonisation alternatives are available. This is especially so if renewable capacity and the willingness to invest in electrolyser capacity is available in the area for industrial use, and if such industries are connected to parts of the RTL (regional transmission gas grid) without other types of end consumers (e.g., built environment) so that gas quality issues are relatively easy to solve.

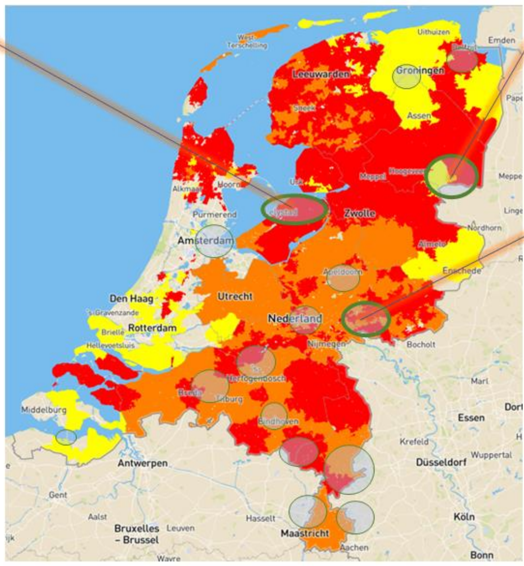
2. Policy recommendations based on D4.1 analysis

In our techno-economic modelling and desk-research-based analysis several types of decentralised industries and processes have been assessed on the issue to what degree they are candidates for switching to hydrogen (blends); also a number of key Netherlands' regions with a potential for introducing hydrogen (blends) to industry have been identified.

The focus in the study on decentralized (so-called cluster 6) industry and local mobility as potential green hydrogen consumers (rather than the five main industrial clusters in the country) was chosen because, as was argued already, unlike the main industrial clusters, the more local industry and mobility hydrogen uptake is typically not easily connected to the foreseen national hydrogen backbone. Therefore, the regional transmission gas lines (RTL) act as their main potential hydrogen grid connections. To identify the country's most suited areas for establishing local hydrogen connections (and hydrogen blending), four location criteria have been combined: the severity of supply side driven e-grid congestion; the presence of local industry with a grid connection decoupled from the built environment/public distribution system (because such a connection would complicate blending); the proximity to (future) renewable energy production sites; and the assumed little industries' decarbonization alternatives. Based on these criteria, some dozen potential 'hydrogen blending regions' were identified throughout the Netherlands, each with multiple possible local blending sites (see figure below).

Area: Lelystad/Swifterbant

Name	Capacity (MW)	Type
Noordermeerdijk	195.0	Wind
Westermeerwind	144.0	Wind
Zuidwester	90.0	Wind
Princess Alexia	129.0	Wind



Area: Emmen/Coevorden

Name	Capacity (MW)	Type
Klazienaveen	1.3 MW	Solar

Area: Doetinchem/Lochem/Hengelo

Name	Capacity (MW)	Type
Solarpark Azewijn	1.8 MW	Solar

Figure 2: Potential blending sites [1]

Modelling the supply side economics of PTG congestion solutions for these regions revealed that, although the PtG option may be promising on the longer term, currently its business case is difficult from the perspective of energy suppliers given the combination of current assumed market prices of green hydrogen and local industry demand levels. Under the present conditions on the whole for energy suppliers in the selected regions trying to deal with e-grid congestion, utility-scale batteries turned out to offer a higher utilization rate and to be more cost-effective to deal with the issue. The latter is due to batteries' scalability and currently lower CAPEX-levels (than electrolysers) and to handsome electricity trading margins given current high electricity prices. Obviously the most economic congestion combatting option for the suppliers of energy will not always coincide with what is most economic from the perspective of the demand side, i.e. industries or mobility sector units in the area off-taking energy. The same may apply if cost conditions alter, e.g. as P2G technology matures.

Moreover, modelling that included next to decentral industry also other potential green hydrogen demand sectors such as mobility, showed that in the optimum the volume of green hydrogen demand from local mobility was mostly much higher than from local decentralized industry. This was because due to the HBE-certificates mobility is expected for the time being to offer much higher green hydrogen returns than industry, although its demand volumes will probably fluctuate more heavily. This finding suggests that **it may be interesting to explore if 'smartly' combined future regional offtake of green hydrogen by both local industry and mobility can provide feasible PtG options.**

Barriers to introduce hydrogen

Interviews with cluster 6 stakeholders on barriers to switching to green hydrogen as energy source revealed that especially not knowing if congestion is a lasting or temporary problem paralyses decisions on whether or not to move to green hydrogen. The same kind of dilemma's apply for RES-investors considering to setting up PtG activity to deal with e-grid congestion: will the electrolyser investment still be feasible if after some years supply-side congestion turns out to be resolved? **It therefore is recommended that authorities provide as clear information as possible on local supply-side congestion perspectives.**

Another barrier from the end users' perspective was the uncertainty if green hydrogen first offered in blends can offer a final solution to ultimately decarbonise completely. The decarbonisation potential of a first, say, 10% hydrogen blend is disappointingly low (≈3% emission reduction), while the blend also reduces the energy content of the gas mix (when compared at constant volumetric flowrate). So, **it is vital that reliable information is provided if local investment in a hydrogen blend really involves a step towards full decarbonisation of natural gas use in decentral industries**: one has to be sure that ultimately one will be able to implement pure green hydrogen via increasing blending percentages.

A third and related perceived barrier is **the regulatory uncertainty if and when the gas TSO and/or DSOs are legally allowed and/or capable to facilitate a 'pure' hydrogen transport connection to the gas grid, or, in the preceding stages, to apply blends of hydrogen in the grid**. This uncertainty therefore **needs to be reduced.**

Opportunities to introduce hydrogen

Local PtG investment and subsequent hydrogen blending can be a first step towards local integration of the electricity and gas systems. This way it can help: offering a solution for local e-grid congestion problems; enhance the profitability of RES investment; and improve local security of supply conditions.

Local PtG investment designed to deal with e-grid congestion can also: act as a stepping stone to synergistically serve an increasing number of end users besides local industry (e.g. mobility and the built environment); and may act as a dominant enabler of a decisive decarbonisation trend in the entire relevant area.

Market conditions for PtG are generally expected to improve as the technologies are scaling up such that ultimately hydrogen may develop into a dominant energy carrier; given this perspective, first-mover issues may have to be taken for granted for the technology to ultimately pay off. Not following this path carries the risk of missing out in the future.

Table 1 summarizes the stakeholder factors mentioned in the interviews concerning local hydrogen blending.

Table 1: Factors per stakeholder mentioned to be taken into account before considering local blending

Type of stakeholder	Crucial factors for stakeholders to consider local blending
RES operator	• Under current market conditions selling electricity is more profitable than producing and selling hydrogen. • Only if a certain amount of congestion hours is in place, it is worth considering to install an electrolyser. • Installing batteries or selling hydrogen to the mobility market generally is considered more feasible than local blending. • A good match between local RES capacity and its potential hydrogen offtake is required to effectively reduce the share of curtailed electricity due to congestion. • As congestion can be temporary, a long-term perspective is required to take investment decisions on electrolyser capacities.
Electricity DSO	• Currently DSOs are allowed to connect wind and solar farms up to 100% of their grid capacity. If a grid is congested it means that no additional solar and wind parks can be connected anymore. • It is expected that future solar and wind farms will not able to offload electricity onto the grid at any time, as it will be allowed to connect up to 150% of grid capacity. • Both batteries and PtG are options to deal with e-grid congestion. The higher the electricity and hydrogen prices, the more economically feasible these options will be.
Gas TSO	• Specific assessments are required of the costs of allowing specific hydrogen blends at local parts of the RTL. For blends up to 10% gas chromatographs have to be replaced involving some (but relatively limited) costs. • **One needs to assess to what degree flexible blending can be handled by the grid and its end-users.** • **The Dutch Gas Law needs to be adapted so that the TSO is legally allowed to facilitate a 'pure' hydrogen connection to the gas grid and apply blends of hydrogen. Also there needs to be clarity if there is a minimum required size for an electrolyser to be connected to the RTL grid.** • **One has to determine if and how any costs of grid adaption for hydrogen are borne by hydrogen users and/or users of the gas grid in general, or by others.**

Industrial off-takers	• Stable and affordable prices of hydrogen, reliability of supply, and a robust infrastructure are key in stimulating industrial use of hydrogen. • Introducing hydrogen in no-regret applications is the best way to stimulate uptake of hydrogen by industry and to create markets and stable demand. • Blending rates up to 20% lead to relatively little decarbonisation, while costs for end-users increase. • Combining onsite hydrogen production and local blending can provide a potentially lower-cost solution (than via electricity from the grid) since the right concentrations can be introduced so that costly upgrading is avoided.

3. Policy Recommendations based on D4.2 analysis

One of the key questions showing up in the above HyDelta2 D4.1 analysis was if ultimately strengthening the grid capacity is the most cost-effective way forward under all circumstances. Could it be feasible if a different strategy can also solve e-grid congestion issues against lower net costs? To answer this question a cost-benefit analysis has been carried out with current data on a quasi-realistic case of supply-side congestion (very similar to the current situation in the eastern part of Friesland, where an investment in a medium-sized (38MWp) solar park is considered). Because of the already existing supply-side congestion, two alternative options present themselves to enable the solar power producer to somehow offload its energy produced onto the market: either the e-grid is strengthened such that it can absorb the additional power provided, or other flexibility tools are developed to achieve the same result, namely a mix of batteries, PtG and accepting some minor curtailment. By considering all the costs and benefits of both options one can answer the question which option is the preferred one from the overall cost perspective of energy production, transport and market uptake combined. Not choosing in favour of the most cost-effective option implies a societal loss.

The results of this study are presented below

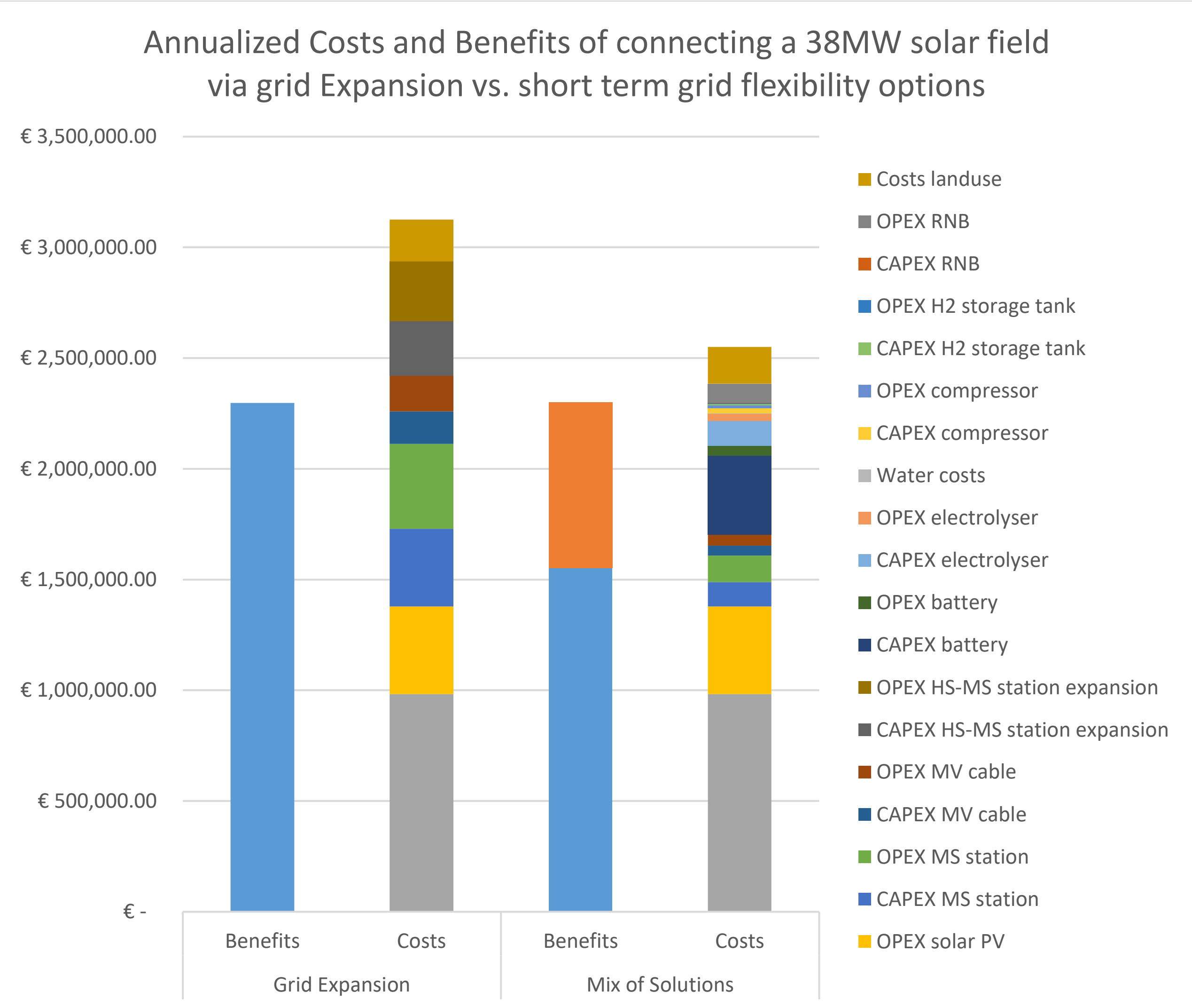


Figure 3: Costs and benefits between grid expansion and the implementation of various grid flexibility solutions

The overall result of the case analysis of newly added solar capacity in a rural supply-congestion region, i.e. where electricity supply already exceeds demand during peak moments, is that under the current (2023) cost and energy price conditions higher stakeholder net benefit can be achieved by connecting the solar park to the market via multiple flexibility options rather than by just reinforcing the local electricity grid.

In practice the found optimal mix of flexibility solutions is not likely to be implemented, among others due to current legislation and market regulations. Distribution grid operators are at least in theory obliged to facilitate all parties that are willing to get a grid connection: local energy producers, consumers but also potential flexibility providers through batteries and electrolysers. In the absence of a mechanism to settle balances between stakeholders to get to the overall optimal result, all parties will manage the operation of their assets with an only view of maximizing their own profits. So, without a proper analysis, coordination and settling mechanism, the optimum solution therefore can and will not automatically be reached (for some further evidence, see alsoHyDelta2 WP2[1] showing that an electrolyser investment run by market prices only will not reduce grid reinforcement costs without additional measures). **Our results therefore clearly indicate that a mix of flexibility solutions can cost-effectively reduce electricity grid reinforcement needs and therefore societal costs, but only if cost-benefit analyses are systematically implemented and new legislation and regulatory measures are introduced supporting that the incentives to get to the optimal solution are implemented. Given the seriousness of the domestic e-grid congestion issues such developments are urgently needed (both for the distribution and transmission e-grid); in fact not having them in place can be seen as a serious obstacle for green hydrogen and battery investment, and a stimulus for growing undue e-grid congestion.**

As far as the flexibility mix considered is concerned, each option has a different role in the mix:

- Curtailment helps to limit grid reinforcements that are only required to facilitate injection of the highest solar generation overshoots for a (very) small number of hours during the year;
- Batteries help to optimizing e-grid capacity use and increasing the local match between generation and demand; and
- PtG helps to better match local supply and demand of energy, especially if there are more structural overshoots of electricity generation in the region. [Note that based on our case analysis it turned out to be more effective to use this electricity to serve demand of other energy carriers in the region, than to invest in the equipment to export the electricity to the transmission grid.]

From the perspective of the growing interest in the role of green hydrogen in the energy system, an interesting issue is under what typical conditions PtG emerges as one of the optimal options of the flexibility mix, assuming that such a mix is optimal from the cost-benefit perspective. This question was addressed by subjecting the same case cost-benefit analysis to sensitivity analyses to identify what factors make the hydrogen option typically beneficial in integrating solar park investment in specific regions. These factors were:

- if regions have a large solar electricity generation capacity relative to their electricity demand (e.g. rural areas with a lot of space for buildings and industrial activity);
- if the price received for hydrogen is high relative to the electricity price, and electrolyser CAPEX costs come down. [Note that the price of 7 €/kg hydrogen for mobility applications assumed in

[1] See HyDelta 2 D2.2 (to be published)

the case study was sufficient to activate PtG in most cases; an assumed 'industrial' price of 2 €/kg, however, not];
- if hydrogen could be delivered to several end use entities in the region. [E.g. PtG showed up in the mix more often when two instead of one HRS was assumed to be located in the region]; and
- if RNB pipeline sections are available for re-use for hydrogen transport, or if the hydrogen demand location is close to the solar park. [Note that compared to hydrogen transport by trucks, transport via the RTL still turned out to be more cost-efficient even if RTL volumes were relatively low compared to regular natural gas RTL pipeline transport].

All in all, our results suggest that it is promising to investigate alternative ways to integrate new local renewable energy capacities, especially in rural regions where large installed capacities of solar or wind generation regularly exceed the relatively small demand for electricity. However, the alternative ways that we identified do require alignment of stakeholders interests and a legislative and regulatory framework that supports this. Therefore, two directions of further investigations can be recommended to bring these findings forward.

Firstly, **it should be identified what specific legislation and regulatory measures would be required to provide the right incentives for solar park and wind farm operators, regional grid operators, and electrolyser and battery operators such that maximum green energy benefits are delivered against lowest overall costs.** A suggestion is to allow distribution grid operators to close dedicated contracts with potential flexibility providers (via batteries and/or small-scale electrolysers) through which a certain revenue stream is guaranteed as long as the flexibility providers operate their assets such that electricity grid reinforcements can be overcome. Another suggestion is to provide incentives such that solar park operators will be inclined to take measures to match their power generation with local demand (thereby overcoming that electricity has to be 'exported' to the national transmission grid).

Secondly, **based on systematic regional prognoses for new decentral renewable capacities and electricity demand, regions should be identified where electricity supply will exceed demand regularly. Together with the beneficial criteria for hydrogen identified above, this information can be used to identify the regions in which decentral hydrogen production is the most promising. Next this information should be made public so that new investors in solar (and wind) capacity and the distribution grid operator can together investigate several options to integrate the additional renewable energy in the system.**

As a more general suggestion **it seems advisable, if significant additional RES capacity instalment is considered, to mandatorily and as a rule ask stakeholders for a cost-benefit analysis of the various ways of handling the electricity to identify the least-cost option from a societal perspective. This rule may apply to both additional RES capacity onshore and offshore, and to both the distribution and transmission grid activity.**

Moreover, since combinations of power-to-gas and batteries and other energy storages to relief grid congestion issues are still in their infancy, **it is important that the first flexibility mix initiatives to reduce e-grid reinforcement needs and related costs can receive an official pilot status, such that for instance the speed of getting licenses and public support can be (much) higher than otherwise.** Because the analysis revealed that the utilization of power-to-gas increases significantly as soon as it is coupled with the battery storage option, **a special subsidy regime should be designed for investment in a combination of power-to-gas and utility-scale batteries or comparable energy storage facilities.**

Finally, one could as a more generic incentive scheme consider to **introduce a dedicated per kilogram hydrogen subsidy (as well as a comparable CAPEX subsidy for battery investment) during a predetermined period to incentivize power-to-gas investment in cases of significant e-grid congestion, but only if cost-benefit analysis clearly shows that power-to-gas (and batteries) will be a part of an optimal mix of flexibility solutions.**

References

[1] Netbeheer Nederland (NBNL), "Capaciteitskaart afname elekrtriciteitsnet," Netbeheer Nederland, 30 March 2023. [Online]. Available: https://capaciteitskaart.netbeheernederland.nl/. [Accessed 07 April 2023].