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THE VALUE OF FLEXIBILITY FOR ELECTROLYZERS

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1. Conclusion

The purpose of this report is to illustrate the value of flexibility, specifically for electrolyzers. The value of the flexibility is quantified as a reduction in the cost per produced unit of hydrogen (LCOH), also considering added costs to unlock the flexibility. The calculations are based on a set of assumptions (section **5.1)**, and it is important to stress that these are associated with uncertainty and that the results are sensitive to changes in the inputs. The aim is to initiate a dialogue between Energinet and relevant parties on how the potential flexibility from electrolysis is optimally introduced to the energy system. The flexibility is crucial to cost-efficiently integrate the massive variable renewable capacities necessary to meet the climate goals.

The value of flexibility introduces a significant reduction for the levelized cost of hydrogen (LCOH) for electrolysis, more than 1 EUR/kg H_2 in average across different scenarios. To realize the potential reduction the electrolysis plant must be able to ramp the input electricity (the faster, the larger potential) and additional electrolysis capacity is required. When minimizing the LCOH, the capacity factor of the electrolysis plant often decreases further and the weighted electricity price increases when including revenue from explicit flexibility services compared to considering implicit flexibility only. The reason is that the revenue from explicit services more than counters the effect of higher electricity prices and the increased investment costs, both in electrolysis capacity and storage.

The value of the implicit flexibility is also significant. The effect enhances the more the electricity prices are fluctuating, as the weighted electricity price for the consumption of the electrolysis can be reduced substantially if consumed in the cheapest hours. Again, the reason is that the decrease in the weighted electricity price gained from the implicit flexibility more than counters the effect of increased investment costs in electrolysis capacity and storage. Storage or flexibility in the processes consuming hydrogen is needed, as the lowest common denominator will be limiting. On the contrary, the value of flexibility increases significantly when having unlimited and free access to storage (i.e. pipelines), which allows flexible consumption to be even more flexible and from a system perspective assist the integration of variable renewables.

This report clearly indicates that the lowest possible LCOH is achieved by investing in additional electrolysis capacity (and hydrogen storage if necessary to unlock the flexibility) to harvest the full value of flexibility, compared to the widespread expectation of approximately 6000 full load hours or more. However, there exists a large predicament as the investment costs increase and so do the risks. To exploit the value of implicit flexibility, one must be exposed to the variations in the day-ahead and intra-day electricity prices. Classical PPAs and other types of hedging strategies limits the incentive to provide implicit flexibility, unless valued by the balancing party. Equally, to exploit the value of explicit flexibility one can't avoid being exposed to the variations in the explicit flexibility markets. In general, the market design for explicit flexibility services procured by TSOs is moving towards shorter market time units (MTU) and auctions the day before operation.

Hence, the potential upside shall be thoroughly compared to the added risks. This cannot be emphasized enough.

The value of flexibility and the impact on the LCOH are analyzed in a model. They are sensitive to changes in the input data, i.e. day-ahead electricity prices and the market price for the explicit flexibility products. Specifically, those two are associated with high uncertainty as they are dependent on the development of the energy system (fuel prices, CO_2-quota price, production and consumption capacities, technology developments, electricity and gas infrastructure, weather data, market designs, etc.). Because of that, different variations have been evaluated to define an expected range of the value of the flexibility. However, the results shall still be used with caution and Energinet cannot be held responsible for the accuracy of the results, the use of the results as a basis for decision-making or any other use, regardless of form or content.

2. Introduction

The purpose of this report is to illustrate the value of flexibility, specifically for electrolyzers. The value of the flexibility is quantified as a reduction in the cost per produced unit of hydrogen (LCOH), also considering added costs to unlock the flexibility. The calculations are based on a set of assumptions explained in section 5.1, and it is important to stress that these are associated with uncertainty and that the results are sensitive to changes in the inputs.

Again, the aim of the report is to initiate a dialogue between Energinet and relevant parties on how the potential flexibility from electrolysis is optimally introduced to the energy system. The flexibility is crucial to cost-efficiently integrate the massive variable renewable production capacities necessary to meet the ambitious climate goals.

When discussing flexibility in the electricity system, the primary focus is often implicit flexibility. Implicit flexibility is reacting on price signals, i.e. to consume electricity when the day-ahead prices are low. However, explicit flexibility from electrolyzers is anticipated to enable cost-efficient balancing of a 100 % renewable electricity system while maintaining the high level of security of supply. Explicit flexibility is active participation in markets where a specific flexibility product is traded. This report focuses on reserves procured by the TSO (transmission system operator, specifically Energinet the Danish TSO), as the reserve markets are the only existing explicit flexibility markets in Denmark. Other products and markets are likely to occur in the near future, i.e. local flexibility demanded by both the TSO and DSOs, but they are not considered in this report.

Furthermore, if engaged with green hydrogen in the Danish energy system please see: https://energinet.dk/Brint (Danish) or https://en.energinet.dk/Hydrogen (English), where Energinet has tried to establish an overview of relevant subjects in the domain of Energinet to be aware of when working with green hydrogen.

Energinet is open to discuss this specific report, and in general how to assist the integration of electrolysis and green hydrogen, including the potential flexibility that follows.

3. Implicit flexibility

In short, energy and electricity prices are dynamic and reflect the balance between demand and supply and/or the available capacity of the electricity grid. This creates a financial incentive for electricity consumers and producers to shift electricity demand to moments in time when prices are low, and electricity production to moments in time where the prices are high.

When introducing more variable renewable production capacity to the electricity system, then the supply side will have larger variations as the production from renewables will vary depending on the weather. As the short run marginal cost of power production from wind turbines and PV is close to zero, then this will impact the electricity price, as the pricing mechanism in the day-ahead electricity market is marginal pricing.

Historically, electricity consumption has been price insensitive, and the production has simply followed the consumption. This might reverse, as controllable production is phased out, the electricity prices are increasingly varying, and new, potentially flexible, electricity consuming technologies are introduced to meet the climate goals.

3.1 Historical prices and simulated prices

Historical and modelled future electricity prices are shown in sorted curves for 2020, 2021, 2025, 2030 and 2040 in **Figure 1** and **Figure 2**. The modelled future prices are based on *'Analyseforudsætninger til Energinet, 2021 (AF21)'*. In 2030, 600 MW of electrolysis is assumed for DK1 and 400 MW for DK2.

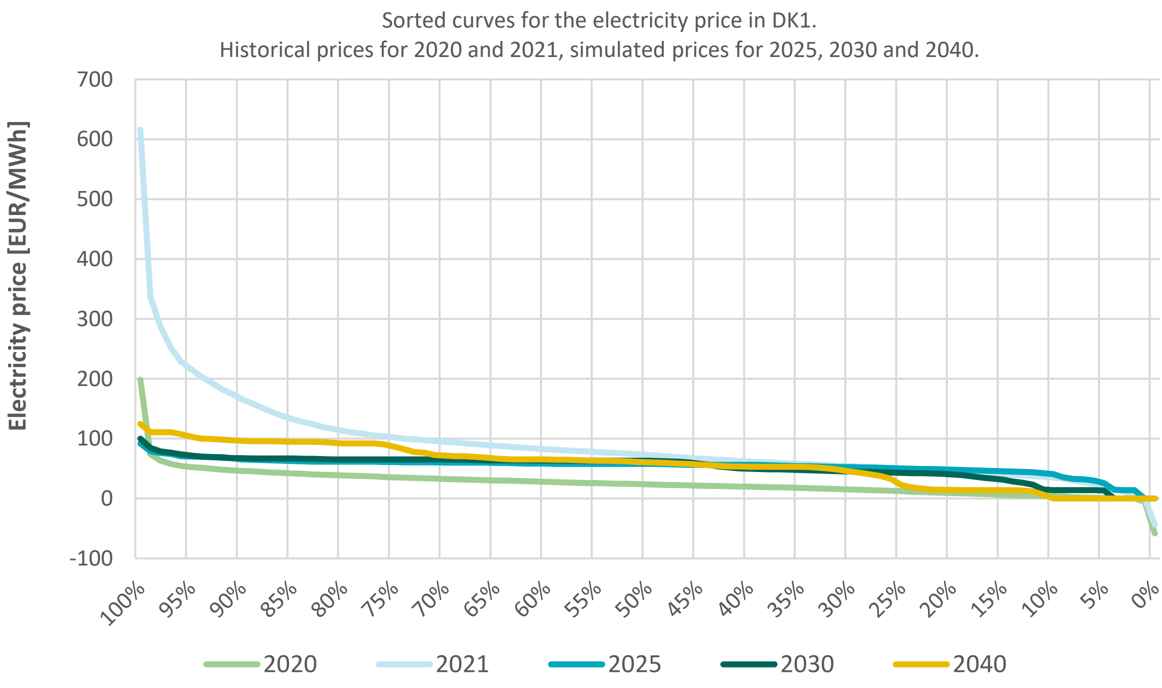


Figure 1: Sorted curves for the hourly electricity price in DK1, shown for historical values in 2020 and 2021, and simulated values in 2025, 2030 and 2040. The simulated values are a result of a model based on the expected future energy system, and the prices are reflecting the marginal costs of the cheapest unit with available capacity.[1]

[1] If interested in the prices, please read more about the underlying assumptions and the prices here: https://energinet.dk/Analyse-og-Forskning/Analyseforudsaetninger/Analyseforudsaetninger-2021 & ELPRISER AF21, NOTAT FEBRUAR 2022

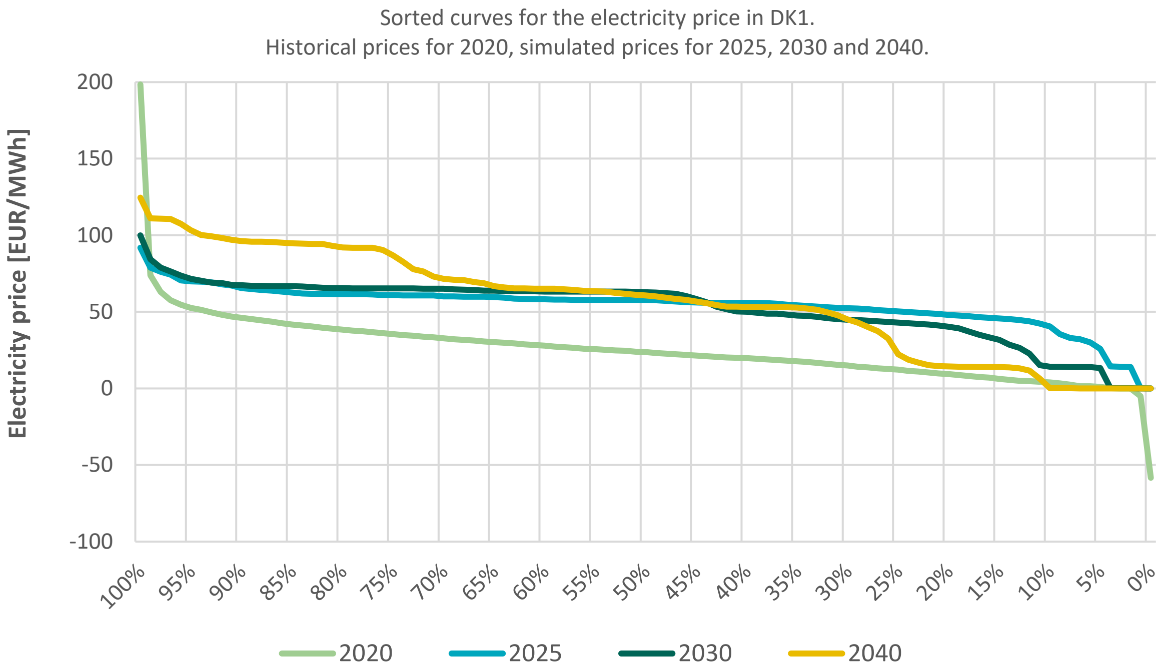


*Figure 2: Identical to **Figure 1**, but without the exceptional year of 2021, where the electricity prices were extraordinarily high.*

In **Figure 3** the average electricity price is shown as a function of capacity factor. The capacity factor describes how many hours of the year a specific electricity consumer will consume. Focusing on electrolysis, a capacity factor of 50 % means that 1 MW of installed electrolysis capacity will consume 0.5 MWh electricity in average, or 1 MWh per hour in half of the hours in a year. The average price as a function of capacity factor, assumes that the consumption has been in the cheapest hours possible. This might of course be difficult to fulfil in reality, but it illustrates the value of flexibility.

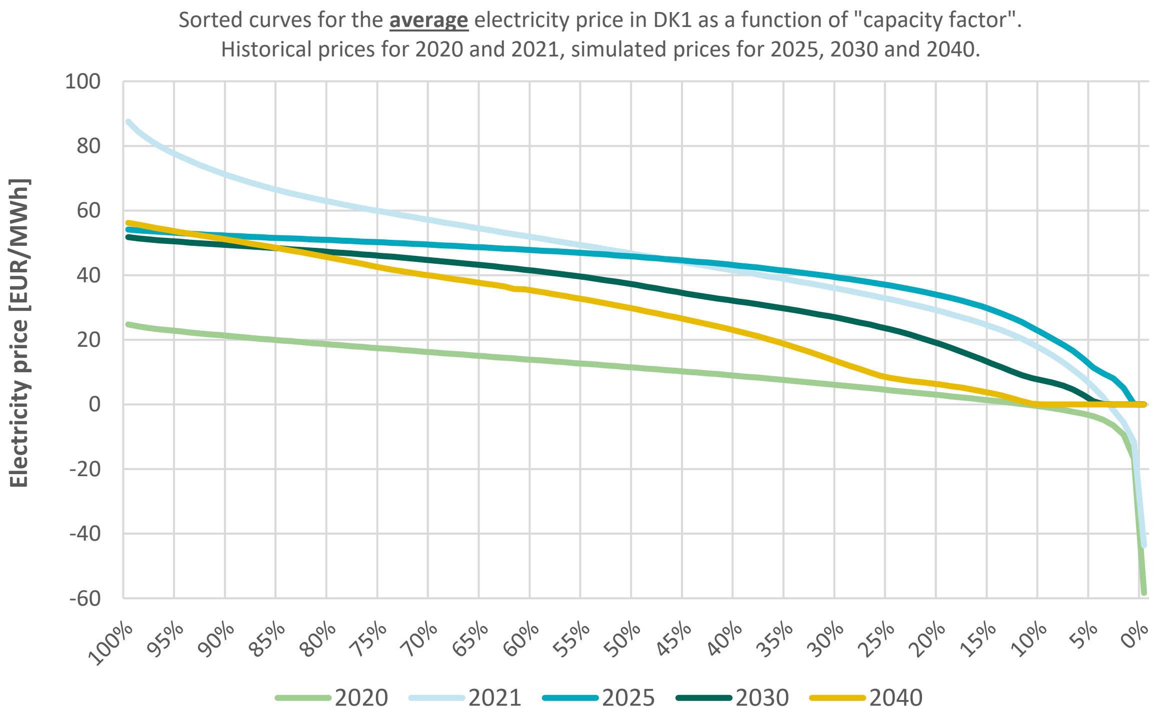


*Figure 3: Average electricity price as a function of capacity factor, based on **Figure 1**.*

It is visible from the figures that the historical prices from 2020 and 2021 have been very different. 2020 is often referred to as a low-price year, and 2021 as an exceptional high-price year. The simulated prices are of course reflecting the nature of the inputs and optimization algorithm, meaning that real-life effects and variations are not necessarily captured.

Similar is available for DK2, and neighboring price areas. Eastern Denmark, i.e. east of the Great Belt is demoted as DK2, while western Denmark, i.e. west of the Great Belt is denoted DK1. Denmark is electrically divided, where DK1 is part of the continental European synchronous area, and DK2 is part of the Nordic synchronous area.

These prices are the input to the analysis in this report, and the results shall therefore be used with caution and Energinet cannot be held responsible for the accuracy of the results, the use of the results as a basis for decision-making or any other use, regardless of form or content.

3.2 “Optimal” capacity factor

If the electricity price & CAPEX are assumed to be the only expenses to produce H_2 in an electrolyzer, then the "optimal" dimensioning to achieve the lowest cost of H2 can be found as a function of the capacity factor. The H_2 demand is assumed to be fully flexible, as the H_2 is produced when the electricity price is lower than the threshold price (being approx. the crossing of the average electricity price & CAPEX curves). This is illustrated for 2020 electricity prices in **Figure 4**. The CAPEX for the electrolysis is found for “*Hydrogen production via alkaline electrolysis (AEC) for 100MW plant*” in the *Technology Data for Renewable Fuels* using the 2030 value[2].

The “optimal” capacity factor and hence dimensioning of the electrolysis plant is very sensitive to the electricity price and also the CAPEX of the electrolysis plant. As seen in **Figure 4**, the optimal value for 2020 electricity prices becomes approximately 44 %. The same consideration is shown for 2025 in **Figure 5**, also illustrating the effect of doubling the CAPEX (which is large!). In general, lower electricity prices will result in a higher amount of full load hours and therefore a higher capacity factor. Few variations in the electricity price (from high to low and vice versa) can have the same effect. Hence, performing the same considerations for the electricity prices of 2021 will reduce the capacity factor significantly compared to 2020.

[2] https://ens.dk/en/our-services/projections-and-models/technology-data

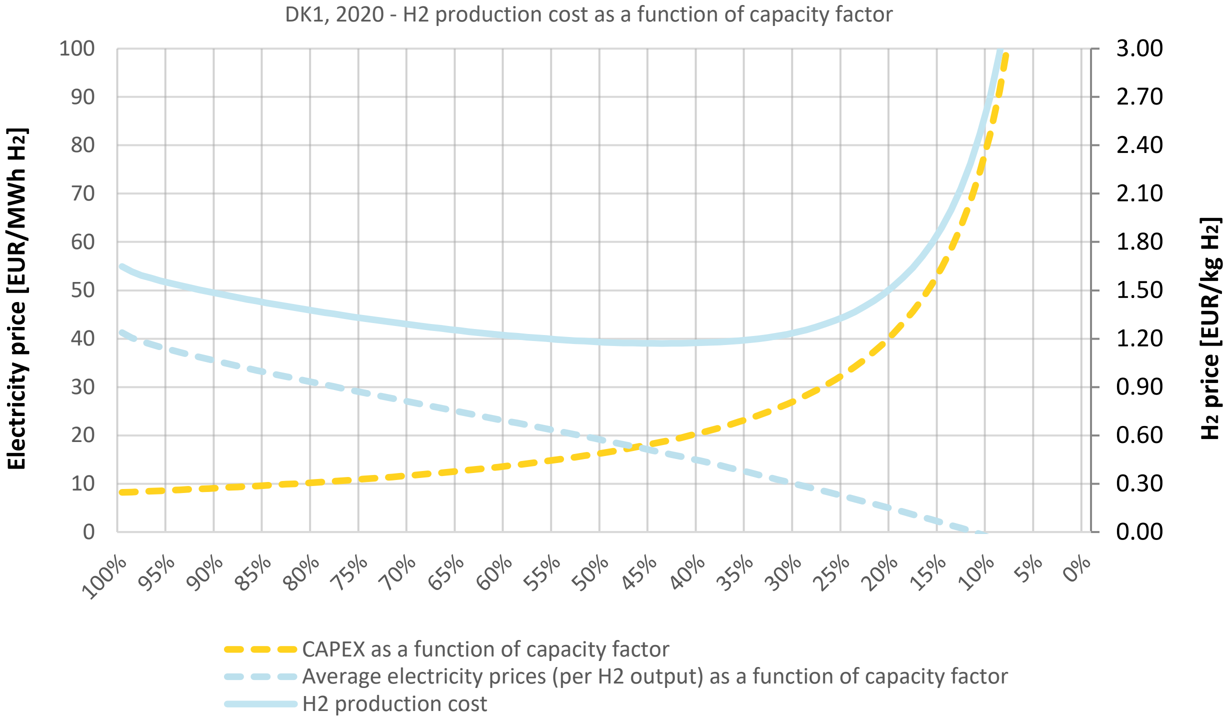


Figure 4: "Optimal" capacity factor found as the minimum H_2 production cost based on CAPEX (divided per produced H_2) and OPEX (assumed to be the cost of electricity).

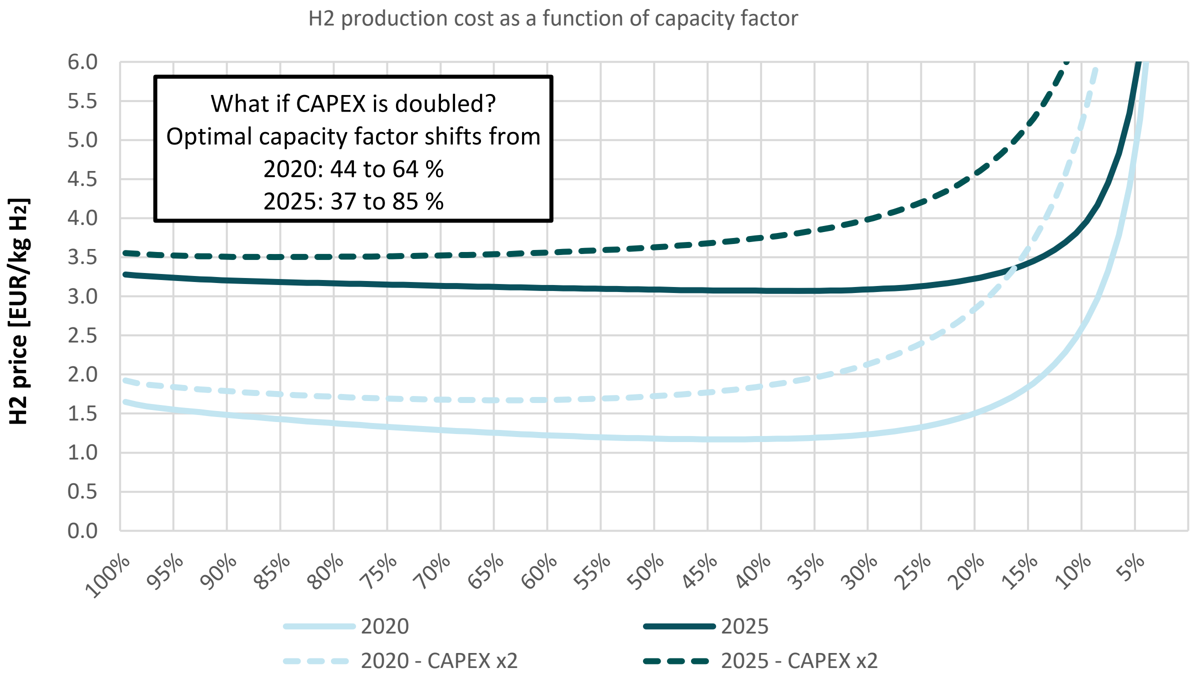


*Figure 5: Similar to **Figure 4** but showing the "optimal" capacity factor for 2020 and 2025 electricity prices and with double CAPEX for both years.*

An increased CAPEX shifts the optimal capacity factor to be higher, as it becomes harder to counter the increased investment costs by a reduced OPEX due to lower average electricity prices. Even though the assumptions behind the CAPEX and OPEX for this "optimal" capacity factor calculation are too simplistic to fully reflect reality, it still indicates a large value for implicit flexibility that should be considered. The optimal capacity factor is sensitive to both the electricity prices and the investment costs, and even when assuming the CAPEX to be doubled, the value of implicit flexibility is significant for years with variations in the electricity price (the modelled year of 2025 shows little variation in the electricity prices, and this is most likely not realistic when comparing to the prices of the last years and the expected rapid development of the energy system).

Hence, it is clearly shown that the lowest possible LCOH is achieved by investing in additional electrolysis capacity to harvest the full value of flexibility (and hydrogen storage if necessary to unlock the flexibility), compared to the widespread expectation of approximately 6000 full load hours or more. The optimal full load hours for almost all tested scenarios falls below 4380 hours (half the year).

3.3 PPA / Nasdaq

There exists but one issue when the investment costs increase, so do the risks. To exploit the value of implicit flexibility, one must be exposed to the variations in the day-ahead and intra-day electricity prices. To manage the risks emerging from the dynamic pricing of electricity one could perform hedging by making an agreement that sets the price level for electricity for a selected time frame. This will limit the incentive to provide implicit flexibility and decrease the value hereof but will reduce electricity price exposure (for both consumer and producer).

An increasingly popular way of doing so is Power Purchase Agreements (PPA). A PPA is a power offtake agreement between two parties, being a (often green) electricity producer and an offtaker of this electricity, such as an electricity consumer or trader. Similarly, Nasdaq can be used. Nasdaq is a global electronic marketplace for buying and selling securities. Nasdaq Commodities offers a broad range of power futures and options that help power traders, producers, distributors and retailers to manage price risks.[3]

Since a PPA is a bilateral agreement, a PPA can take many forms and is usually tailored to the specific application. A PPA can be both physical and financial. PPA defines the conditions of the agreement, such as the amount of electricity to be supplied, negotiated prices, accounting, and penalties for non-compliance.

As an example, one could imagine that the balancing fee reflecting the costs to match consumption and production (for financial PPAs) would be tailored to the new types of large and flexible electricity consumers, especially when paired with variable renewables. The balancing party, when managing large PPA portfolios, could actively manage risks if agreed so with the flexible consumer and hence reduce the balancing costs. It is therefore not necessarily true that PPAs reduce the value of implicit flexibility while reducing electricity price exposure.

[3] https://www.nasdaq.com/solutions/nordic-european-power

4. Explicit flexibility markets in Denmark

In any power system, a balance must always be maintained between production and consumption of electricity to avoid black/brown outs. Changes in production/demand and disturbances affect the system balance and cause grid frequency deviations and changes of loading of grid components. Energinet buys ancillary services to always ensure access to such resources that are necessary to ensure the stable and reliable electricity system operation. Grid operators across the world are in similar fashion ensuring access to similar services.

The demand for ancillary services is dependent on the nature of the electricity system. Larger systems have a relative lower demand, and smaller system often requires faster services as the stability is more challenging to maintain.

The ancillary services which are procured from electricity producers and consumers in Denmark and in neighboring countries are used for various purposes, and different requirements therefore apply to the supply of the various services. Furthermore, the requirements and tender conditions to be met by suppliers of ancillary services vary, depending on whether the services are to be supplied in eastern Denmark (DK2) or western Denmark (DK1).

For simplicity the emphasis is put on active power reserves in DK1 as there exists “only” three active power reserves, while there exists five in DK2.[4,5] In DK1, and the rest of the continental European synchronous area the three types of reserves (with almost identical technical requirements in each country, but varying tender conditions). The reserves are denoted:

- Frequency containment reserve (FCR)
- Automatic frequency restoration reserve (aFRR)
- Manual frequency restoration reserve (mFRR)

The Danish demand for the reserves and the amounts procured on the explicit markets for the reserves are described in an annual publication by Energinet.[6] The main takeaways are described in **Table 1**, as are market specifications.

[4] For further information please see: https://en.energinet.dk/Electricity/Ancillary-Services. Specifically, the tender conditions and technical requirements (prequalification and test).

[5] Energinet has created introduction material to ancillary services, as the topic is not well-known and complex at the same time. Please see the following in Danish: https://energinet.dk/El/Systemydelser/Introduktion-til-Systemydelser/Oversigt-over-systemydelser & https://energinet.dk/El/Systemydelser/Introduktion-til-Systemydelser/Introduktions-materiale

[6] https://energinet.dk/El/Systemydelser/Markedsgoerelse-og-behovsvurdering

DK1	FCR	aFRR	mFRR
Purpose	Automatically contain and stabilize the frequency when incidents occur	Automatically restore frequency and balance in a specific geographic area (bidding zone)	Manually restore frequency and balance in a specific geographic area (bidding zone)
Technical specifications			
Reaction time, see Figure 6	Maximum 30 seconds	Maximum 15 minutes (5 minutes from 2024)	Maximum 15 minutes (10 minutes from 2024)
Minimum endurance	Approx. 20 minutes	Continuously in the contracted period	Continuously in the contracted period
Characteristics	The provider measures frequency and provision is required when frequency deviates outside given thresholds.	Energinet continuously forwards an activation signal based on requested activation.	Energinet activates providers per market time unit (MTU), currently per hour, but per quarter in ultimo 2023.
"Load factor"[7]	Net ~0 % ~1 % both down and up	Net ~12 % ~38 % down and ~26 % up (as mFRR in 2024[8])	100 % as the reserve is either activated or not. Activation is performed via the separate energy activation market.
Market specifications			
Minimum bid size	1 MW	1 MW	5 MW
Maximum bid size	N/A	50 MW	50 MW
Procured as	Symmetric product	Symmetric product (asymmetric for both up- and downwards regulation in 2024)	Asymmetric for upwards regulation only, seen from the power system perspective.
Market time unit (MTU)	4 hour block (6 blocks a day)	1 month (as mFRR in 2024, GCT 7.30 a.m.)	1 hour
Gate closure time (GCT)	8 a.m. the day before operation (before day-ahead)	2nd last working day before the coming month	9.30 a.m. the day before operation (before day-ahead)
Danish demand procured	+/- 20 MW	+/- 100 MW	+ 284 MW (up to 584 MW when sharing with DK2 is not possible)
Capacity market	Yes	Yes	Yes
Market size	Common central European market, with limited exchange possibility for DK1 due to grid constraints.	National (will be common Nordic in 2024)	National (will be common Nordic ultimo 2022)
Energy activation market	No	No (expected in 2024)	Yes (the regulating power market)
Pricing mechanism for capacity market	Marginal pricing	Pay-as-bid (marginal pricing in 2024)	Marginal pricing
Pricing mechanism for energy activation	Settled as imbalances (as the net energy activation is insignificant)	Day-ahead price +/. 100 DKK/MWh (as mFRR in 2024)	The balancing price (marginal price on the regulating power market)
Balancing responsibility	No	Yes	Yes

Table 1: Main technical and market specifications for reserves in DK1 (with coming changes).

[7] Load factor is defined as the required average historical provision of energy per sold amount of reserve capacity. 1 % load factor and 1 MW of sold reserve capacity will in average result in 0.01 MWh of energy per hour. For FCR this is calculated with the allowed deadband around 50 Hz.

[8] When DK1 and the rest of the Nordic synchronous area enters the common European energy activation platform for aFRR, PICASSO.

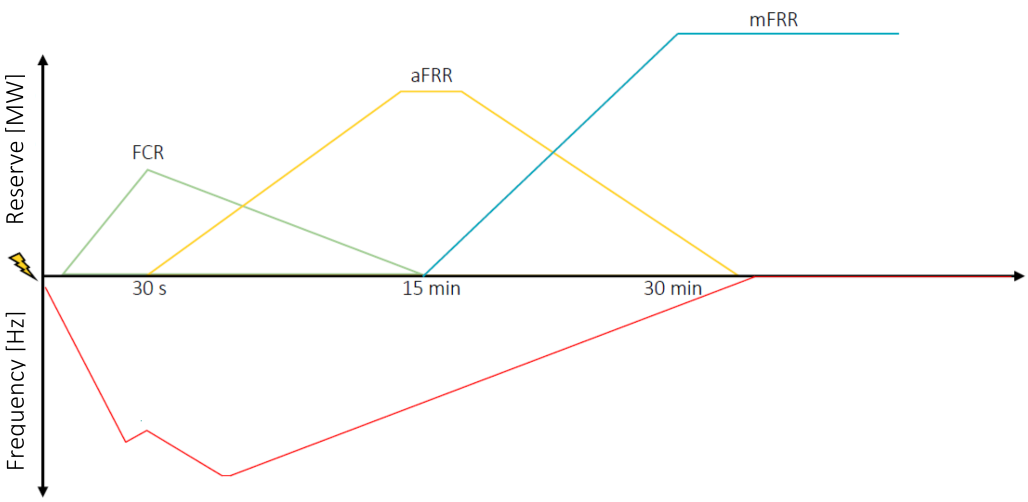


Figure 6: Illustration of FCR, aFRR and mFRR maximum activation times (presently for DK1)

4.1 Future market design for mFRR and aFRR

Nordic power grids are closely coupled, and Nordics have a long history of cooperation for balancing. The Nordic power system is transforming towards more unregulated production like wind and solar and increased cross-border exchange. Therefore, markets get a finer granularity (both time and geography), and more trade is taking place closer to the operational hour. To meet these changes, Energinet and the rest of the Nordic TSOs are developing the Nordic Balancing Model (NBM).[9]

New common capacity markets are planned for aFRR and mFRR, where both DK1 and DK2 will join. The common capacity markets will allow each Nordic TSO on an hourly resolution to procure reserve capacity for aFRR and mFRR cross border. The result of the auction will aim to minimize the total cost on a Nordic level to meet the reserve demands, also considering the costs of allocating interconnector capacity to exchange of reserves (that could have been used to transmit energy if not reserved for exchange of reserves).

Common energy activation markets are also planned for aFRR and mFRR (for mFRR it will be an update of the current common Nordic regulating power market). The aim is to minimize the total Nordic costs for the required activation of balancing energy, taking grid constraints into consideration. Similarly, European energy activation platforms for balancing energy are being developed, denoted MARI for mFRR and PICASSO for aFRR.

4.2 Capacity and energy activation markets

For the reserves with significant energy activation, aFRR and mFRR, capacity and energy activation are split into two markets.[10]

The capacity markets are to ensure sufficient access to balancing energy in the energy activation markets. Hence, a given minimum is procured in the capacity markets. The procured reserve capacity is obliged to submit bids to the energy activation markets. Therefore, the capacity markets function as an availability payment, for the TSO to ensure access to bids on the energy activation markets.

[9] https://nordicbalancingmodel.net/ & https://energinet.dk/El/Systemydelser/Nordic-Balancing-Model

[10] For aFRR when entering PICASSO in 2024.

The energy activation markets are to ensure the activation of the cheapest balancing energy when necessary. The pricing of energy bids that have received a capacity payment is completely decoupled from the pricing of the capacity bid. Energy bids, that has not received a capacity payment in the capacity markets, are denoted voluntary bids. Hence, when the TSO experience an imbalance, the cheapest balancing energy bids can be activated to restore balance.

The technical requirements are technology neutral, and consumption, production and storage units are all allowed to participate in the capacity and energy activation markets.

4.3 Cost of providing reserves for electrolysis[11]

When providing reserves, one must consider the cost of doing so. This is closely linked to the market design and expected activation pattern.

The pricing mechanism for all the capacity and energy activation markets is marginal pricing (for aFRR in 2024). The bidding strategy is therefore to bid the short run marginal costs and gain a profit when a more expensive bid sets the price of the market.

4.3.1 Capacity markets

When selling availability of capacity from an electrolysis plant one should consider if the plant would operate at the needed loading without the expected revenue from reserve provision.

To exemplify, hydrogen is assumed to be sold as a commodity in an existing hydrogen infrastructure, or sold in a long-term contract. Hence, a given price of the hydrogen is known. If the electricity price is below a given threshold value, then the short run marginal cost of the hydrogen production for this specific electrolysis plant is lower than the market price. Therefore, the electrolysis plant would be consuming even without a revenue from selling reserve capacity. The cost of providing upwards regulation (the ability to reduce consumption) is therefore zero, but the cost of providing downwards regulation (the ability to increase consumption) is the lost profit of producing hydrogen equal to the difference between the short run marginal cost of the hydrogen production and the market price for the hydrogen. For symmetric products, the electrolysis plant would have to operate at partial loading with sufficient capacity in both directions to provide the sold reserve capacity.

If no commodity market for hydrogen exists, one would have to compare the cost of producing hydrogen at different hours. Assuming a constant hydrogen demand, one would also have to include the cost of storing hydrogen or the loss of not providing the hydrogen. This is more complex as the aim is to meet the hydrogen demand in the cheapest possible way, but this is dependent on the variations of the electricity and reserve prices, etc.

To increase the complexity even further, the day-ahead electricity price is not known at the time of bidding for the reserve markets in DK1. Even with the known future changes to the capacity markets, the GCT of both FCR, aFRR and mFRR will be before day-ahead. If the electrolysis plant is exposed to the day-ahead electricity price, one would have to rely on forecasts. Similarly, when bidding for FCR (at 8 a.m. before the day of operation) the prices of mFRR are not known. Hence, the pricing of bids for FCR should also include considerations for the pricing of mFRR, etc.

[11] Energinet has developed a specific case for electrolysis based on fictive data to describe what provision of explicit flexibility is: https://energinet.dk/El/Systemydelser/Introduktion-til-Systemydelser/Case-beskrivelser

For the reserves with a capacity market only, which is FCR in DK1[12] (as the energy activation is insignificant), the expected activation pattern found from historical data should also be considered. The grid frequency is converted to activation requests and historically this has resulted in a very low amount of energy but with many minor activations. If minor activations stress the plant and perhaps has an impact on degradation and lifetime, the estimated costs of this should also be included in the bidding price for the specific reserve.

4.3.2 Energy activation markets

Again, when selling energy activation from an electrolysis plant one should consider the costs of changing the loading of the plant. What is the profit or loss when increasing or decreasing electricity consumption at a given electricity price?

I.e., if the short run marginal cost of hydrogen production based on the day-ahead electricity price is competitive with a given hydrogen market price, then the cost of providing downwards regulation is zero (assuming the day-ahead price to be the reference). On the other hand, the cost of providing upwards regulation will be equal to the lost profit of producing hydrogen.

For the energy activation markets, the day-ahead electricity price is known and therefore the considerations become simpler. Again, for the case with no commodity market, one would have to compare the cost of producing hydrogen at different hours. When providing upregulation in a period where the hydrogen production is reduced, the “lost” hydrogen production should be recovered at another period. A profit will only be earned if the total cost of producing a given amount of hydrogen is reduced.

[12] aFRR will have a separate energy activation market, expected in 2024 when Denmark joins PICASSO.

5. Model description

To be able to thoroughly analyze the value of both implicit and explicit flexibility, a model has been developed. The model is formulated as a linear optimization problem with the objective function to minimize the total cost of providing a specified hydrogen demand.[13]

The model has multiple possibilities to define different variables and constraints, as well as variations in input parameters.

The model can simulate a hydrogen demand that must be met either with an isolated hydrogen production, or that in combination with a commodity market for hydrogen with a given price (where hydrogen can be traded at a specified price).

The model can work with investment variables for the dimensioning of the electrolysis plant, grid connection capacity, hydrogen storage, and battery and renewable capacity behind the meter. The investment variables for the storages are split in energy and charge/discharge capacity. The plant dimensioning can also be specified as a fixed value.

Furthermore, hourly variables that the model can freely choose within the given constraints are the electricity consumption for the electrolysis, the reserve provision per technology, charge/discharge of storages, etc.

The main constraint is the energy balance, that production and consumption of energy must be equal. Both for electricity and hydrogen. The plant dimensioning must of course be respected, equally the grid connection constraint where i.e. downwards regulation can't be provided if the full grid connection capacity is already allocated to consumption for the electrolysis as the total plant cannot increase the offtake from the grid any further. Similarly, upwards regulation cannot be provided if there is no consumption for the electrolysis or other technologies that can provide the reserve.

5.1 Assumptions

5.1.1 Perfect foresight

The model is built to solve for a year at the time. For the full year, the model has perfect foresight, meaning that it knows the hydrogen demand, electricity prices, reserve prices, etc. for all hours of the year (before it starts optimizing). This is of course unrealistic, and a partial solution is to introduce a fixed hydrogen demand and an upper limit for hydrogen storage, to force the model to consider shorter periods at a time. However, the complexity concerning chronology of the GCT of the reserve and day-ahead markets and the dependency on forecasts is not reflected.

5.1.2 Price taker

The model is assuming that the defined plant is a 'price taker' on all markets. Depending on the size of the plant, this reflects reality more or less. The procurement of reserves in DK1, as stated in Table 1, is presently 20, 100 and 284 MW for FCR, aFRR and mFRR respectively. This is expected to increase in the future, but for large plants (i.e. 1 GW electrolysis) the assumption is definitely challenged. Similarly, utilizing the historical prices for both reserves and day-ahead electricity as input to the model will also be increasingly challenged as the energy system

[13] The model to perform the analysis is developed by Energinet in close dialogue with Green Hydrogen Systems, as part of an internship. The model will be made available on Energinet webpage, if desired by stakeholders. The input data are publicly available, and the software is open source.

changes in the future. Again, if multiple GW electrolysis plants are implemented and providing reserves, then it will have an impact on the future prices especially for reserves as the liquidity on the markets will increase significantly. Hence, multiple scenarios are investigated using simulated day-ahead electricity prices for the expected future energy system and variations in the reserve prices. For reserves a constraint on maximum reserve capacity that can be sold is also implemented in the model.

In general, larger plants must be more wary of this assumption and all if the flexible electrolysis capacity increases rapidly. Specifically, for the pricing of reserves as these markets are easier to cannibalize than the larger energy markets. However, the reverse situation can also occur, i.e. that the current providers of reserves are slowly phasing out while no new providers replace them. Similarly for the day-ahead electricity price, that more renewable production capacity is introduced than forecasted and not met by an equal increase of consumption.

5.1.3 Reserve markets

The markets are modelled on hourly resolution, both for day-ahead and for reserve capacity. Similarly for hydrogen, if used. Energy activation markets are not included in the model, as the profit gained from energy activation markets for electrolysis is expected to be much lower than the capacity markets. Furthermore, perfect foresight in the energy activation markets is unrealistic as the activation is determined by the system imbalances, which are stochastic.

5.1.4 Input data

The input data consists of historical or simulated prices, which all are public and accessible at the Energinet webpage. If including renewables behind the meter, then hourly load factors are also used to find the maximum production per technology per hour (these also vary per year). The CAPEX values for the investment variables are found for 2030 in the *Energy technology catalogues*[14], which are also public. The ones used are atmospheric AEC for 100 MW plants and steel tubes for hydrogen storage. Energy consumption for compression for the storage is also found here.

For pressurized AEC the overall plant electricity to hydrogen efficiency is conservatively assumed to be 60 % (not changing with the loading), and the recoverable heat at temperature levels sellable to the district heating grid is assumed to be 20 % of the electricity input. The latter is however not included as a revenue in the base scenario. A higher efficiency would impact the LCOH, but not the value of the implicit flexibility significantly. Hence, a conservative estimate is used.

To reflect the expected changes of the tariffs in Denmark[15], a best guess is used. The tariffs are expected to be divided into a capacity and energy part. The capacity part is per MW of grid connection, and the energy part is per MWh of consumed electricity from the grid. For larger electrolysis plants (above 100 GWh/year of electricity consumption from the grid) the energy tariff is reduced, and similarly if connecting with limited access (not allowed to consume if the grid is overloaded) the capacity tariff is reduced.

As the tariffs are not affecting the results significantly for the main scenario with a fixed hourly hydrogen demand and no renewable production behind the meter, it is loosely assumed to be 50 DKK/MWh and 27.500 DKK/MW/y (a mix of full and limited grid connection access).

[14] https://ens.dk/en/our-services/projections-and-models/technology-data

[15] https://energinet.dk/Om-nyheder/Nyheder/2021/11/04/Energinet-vil-aendre-elforbrugernes-systemtarif

As the model runs for a year the investment costs are found per [DKK/MW/y] equal to the CAPEX [DKK/MW] divided by the technical lifetime [y], summed with the annual fixed OPEX [DKK/MW/y]. As depreciation is not accounted for the WACC (weighted average cost of capital) is set higher than usual, at 15 %. The economic lifespan could have been used instead.

The last input data is the regulating capability for each technology per reserve. I.e., how much can 1 MW of electrolysis provide of FCR, aFRR and mFRR considering the activation times per reserve? Minimum loading and forecast precision (only for renewables) are also included in this consideration. For electrolysis, 80 % of the nominal capacity is assumed to possible to provide as mFRR (asymmetric), 40 % as aFRR (symmetric) and 20 % as FCR (symmetric).

5.1.5 Reserve and day-ahead electricity prices

In **Figure 7**, **Figure 8**, **Figure 9**, **Figure 10** and in the **Appendix** an overview of the historical reserve prices and the historical and simulated day-ahead electricity prices, that are used as input to the model, is given as distributions. The distributions are created from the hourly prices, given per hour for both the electricity and reserve prices.

2020 was a low-price year considering the electricity prices, and 2021 was an extraordinarily high-price year, as seen in **Figure 10**. This had an effect on the mFRR prices, as seen in **Figure 9**. However, FCR has an opposite pattern as DK1 joined the continental European market for FCR in early 2021, which lowered the prices as seen in **Figure 7**, despite the increase in day-ahead prices. aFRR has been roughly the same for 2020 and 2021, as shown in **Figure 8**. DK1 has presently a monthly market, hence the costs are also influenced by managing of risks. As the model assumes hourly markets for reserves, an aFRR price distribution is constructed for 2021 based on the expected future market design per hour with potential cross border exchange if the aFRR price delta between the bidding zones is larger than the day-ahead price delta. Hence, the monthly price in DK1 is assumed to be the hourly price, unless outcompeted by the hourly aFRR price in neighboring bidding zones + the day-ahead delta and a margin of 2 EUR/MW.

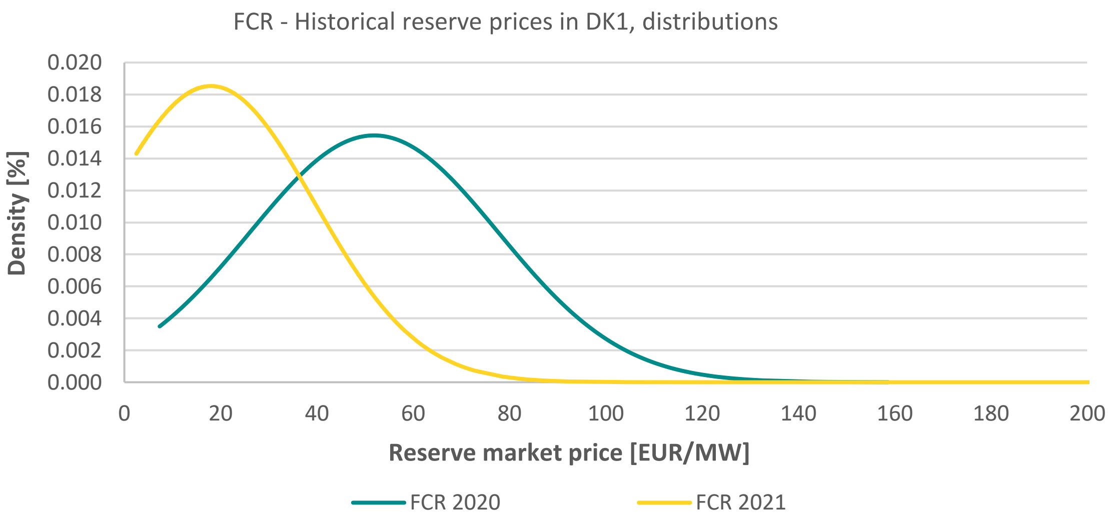


Figure 7: Historical FCR prices for DK1 for 2020 and 2021

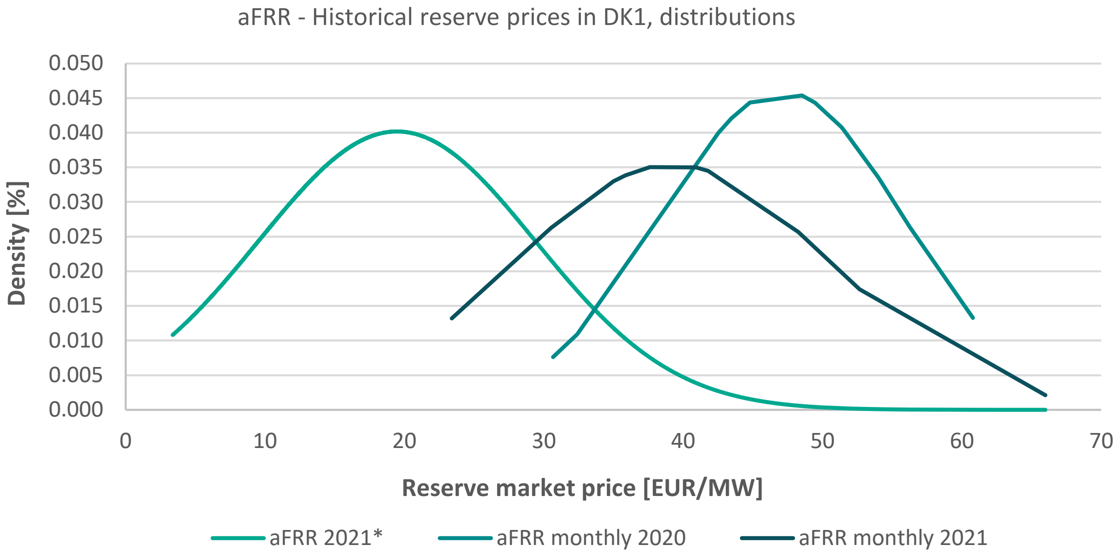


*Figure 8: Historical aFRR prices for DK1 for 2020 and 2021. The * indicates that the price has been constructed based on the expectations for the future market design, implemented on the historical prices. The future design is a common capacity market in the Nordics, where aFRR can be exchanged cross border but only if the aFRR capacity price difference is larger than the day-ahead price difference plus a margin (set to 2 EUR/MWh). Germany is included in the calculation, and it is only performed for 2021 as there does not exist sufficient aFRR market prices for neighboring bidding zones in 2020.*

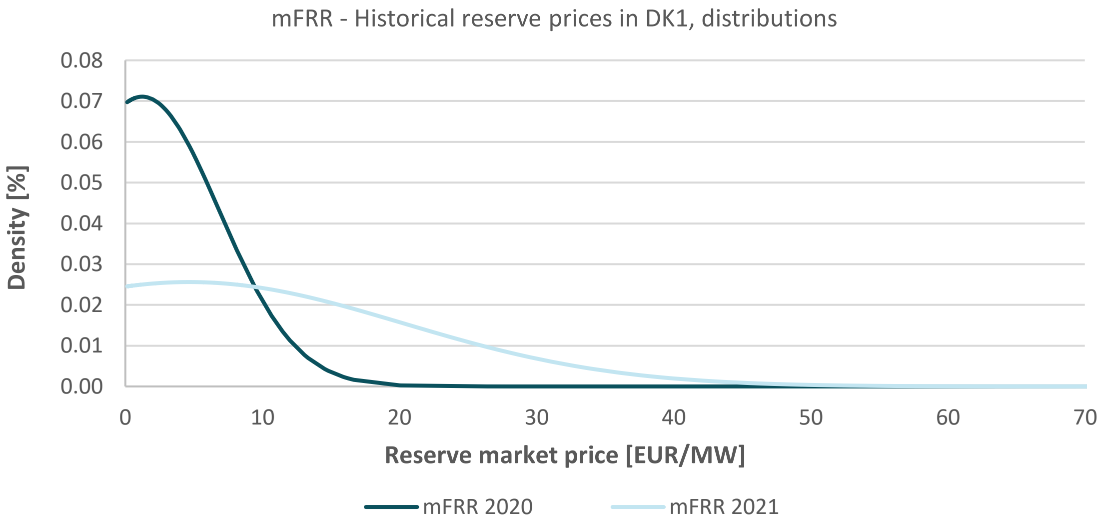


Figure 9: Historical mFRR prices for DK1 for 2020 and 2021

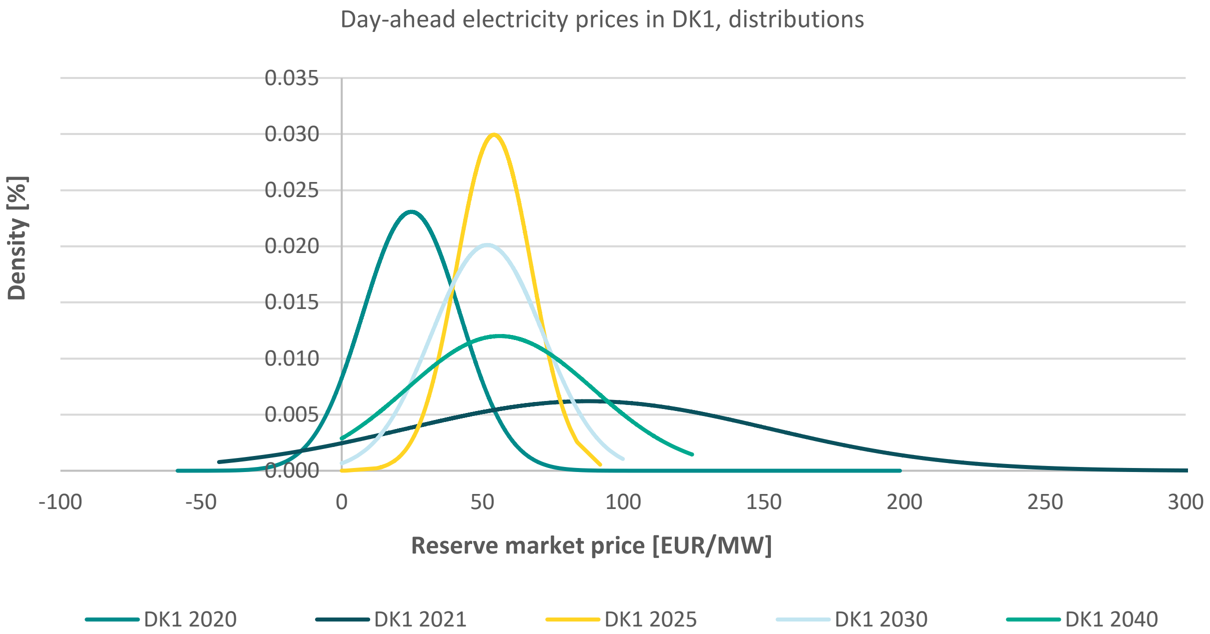


Figure 10: *Historical day-ahead electricity prices for DK1 for 2020 and 2021, and simulated prices for 2025, 2030 and 2040 based on expected developments of the Danish energy system.*

6. Modelling results

The results are very sensitive to the input data, as there are large variations in the prices of the electricity and the reserves depending on the modelled year. The results in this section are based on a defined fixed hourly hydrogen demand, that must be provided by onsite electrolysis with the possibility to utilize storage, as defined per scenario. For an example of the hourly dynamics of a modelled year, please see the **Appendix.**

Figure 11 shows the resulting hydrogen production costs for two (non-reserves) scenarios per different electricity-price-years. The first scenario is with the possibility to invest in onsite H_2 storage (if feasible), and the second is with free unlimited H_2 storage, mimicking hydrogen pipelines. The two different scenarios show the difference between having perfect foresight and an unlimited amount of storage, compared to limited storage and hence to be forced to operate based on short term decisions and expectations.

As **Figure 11** shows the total cost of electricity (shown as the weighted electricity price in **Figure 12**) consumed by the electrolysis is significantly lower for the pipeline-scenario, as expected. Especially for years with large fluctuations in the electricity price, 2021 and 2040 as shown in **Figure 10**, which also are the years with the largest invested storage capacities for the onsite-storage-scenarios.

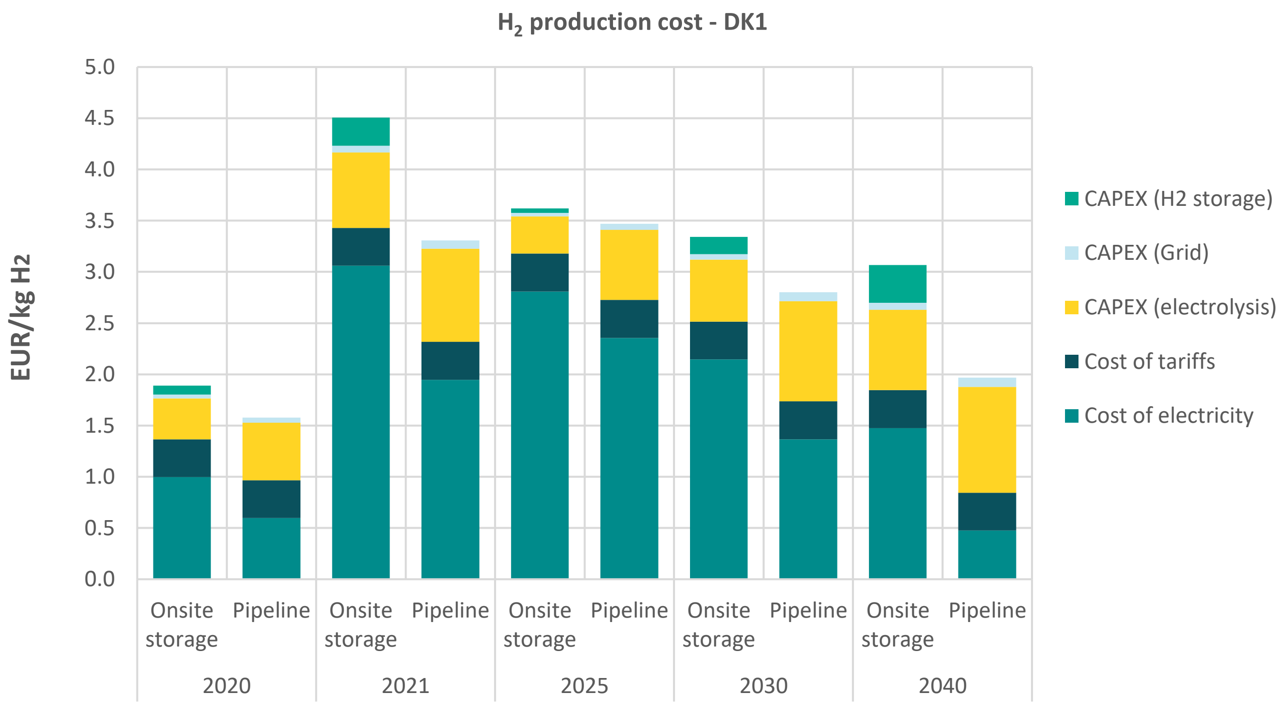


Figure 11: The resulting optimal average cost of producing hydrogen for the electricity prices of 2020, 2021, 2025, 2030 and 2040 respectively. The scenarios per electricity price year are shown, one where CAPEX for onsite hydrogen storage is included in the optimization, and one where limitless storage can freely be accessed (mimicking a pipeline).

Figure 12 shows the optimal capacity factor for the 10 runs in **Figure 11**. The capacity factor is calculated as the invested electrolysis capacity relative to the fixed hourly hydrogen demand. The optimal capacity factor is correlated to the distribution of the electricity price. The more distributed, the lower the capacity factor.

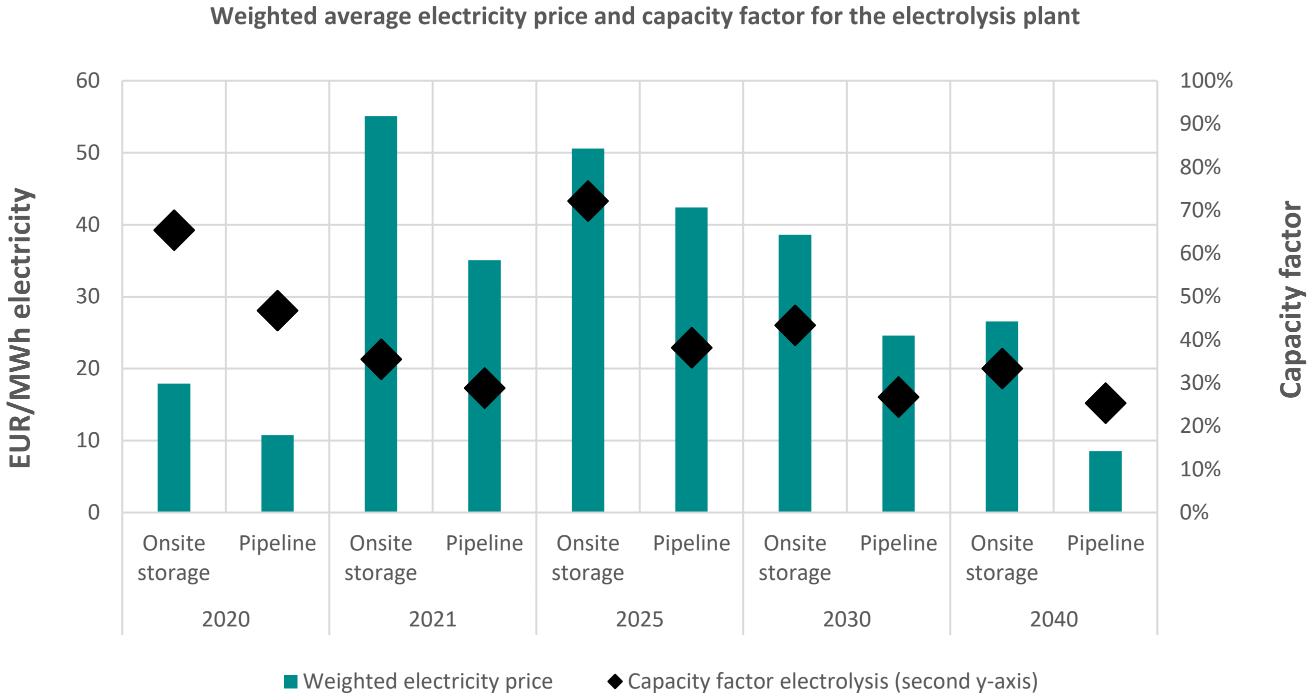


*Figure 12: The resulting weighted average electricity price and capacity factor the electrolysis plant for the scenarios shown in **Figure 11**..*

When analyzing the specific electricity-price-year of 2021, pre-determined capacity factors are defined to see the impact on the average cost of hydrogen. Five scenarios are chosen, 100, 80, 60, 40 and 20 % capacity factor respectively, as shown in **Figure 13**. Naturally, the CAPEX of the electrolysis increases when the capacity factor decreases. More storage is invested in to harness the value of the flexibility with the lower capacity factor, and the cost of electricity decreases as a result of this. As found in **Figure 12**, the optimum capacity factor is 36 % which is also indicated by **Figure 13**.

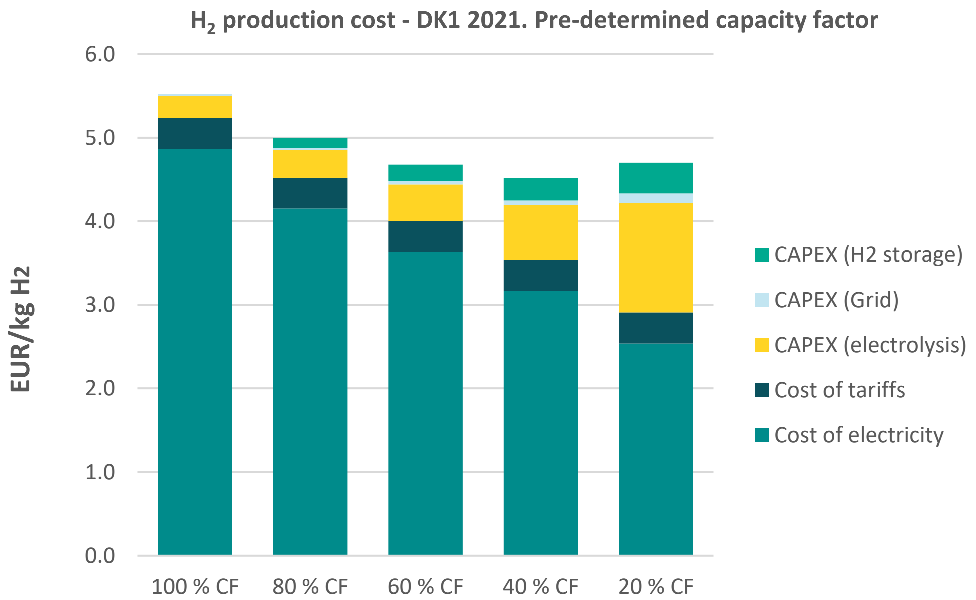


Figure 13: The resulting average cost of producing hydrogen for the electricity prices of 2021, when locking the capacity factor and hence not allowing the model to invest in an optimal electrolysis capacity

When investigating the value of explicit flexibility based on historical prices and the 'price taker' assumption, the resulting cost of hydrogen is compared for 2020 and 2021 based on pre-determined capacity factors, similarly to **Figure 13**. The revenues from the capacity markets are summed and shown as a negative contribution in **Figure 14**. For 2020 the optimal capacity factor is pushed down towards 20 % (from 65 %), and the resulting hydrogen production cost is even negative. The 2020 prices for FCR and aFRR were very attractive for electrolysis, hence this should be taken with caution. For 2021, the constructed aFRR price based on the expected future market design is used, and the FCR price is also a result of the common European market as DK1 joined in January 2021. As also seen on the revenue for reserves for 2021, this is significantly lower compared to 2020. Furthermore, the resulting absolute reduction in hydrogen production cost as a function of the capacity factor is equally smaller for 2021.

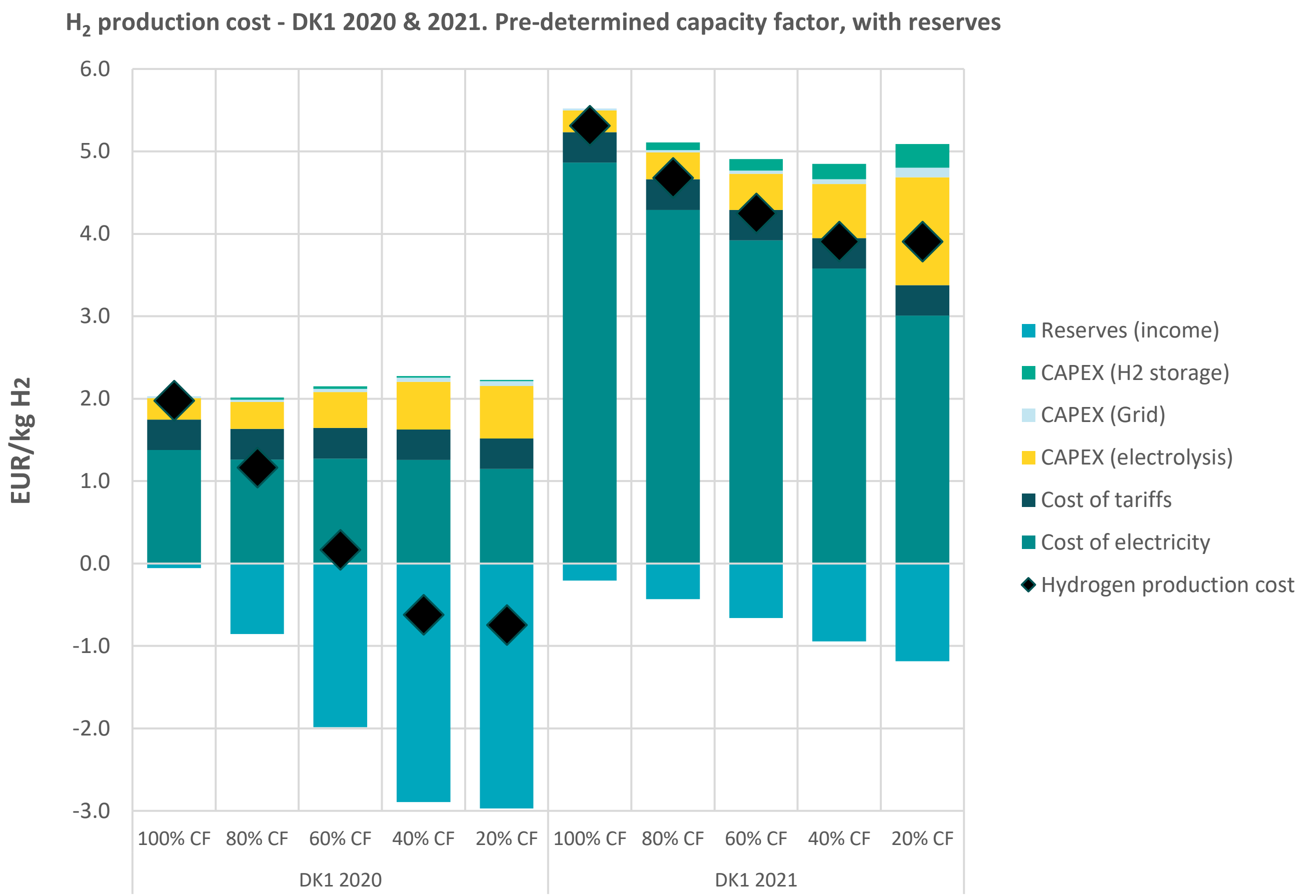


__Figure 14__: The resulting average cost of producing hydrogen for the electricity prices of 2020 and 2021, when locking the capacity factor and hence not allowing the model to invest in an optimal electrolysis capacity. The electrolysis can provide reserve and earn the prices shown in __Figure 7__, __Figure 8__ and __Figure 9__. For 2021 the constructed aFRR is used.

In **Figure 15** the optimal results for different scenarios for 2021 are shown. The base case with and without reserves, and with and without reserves for double CAPEX for electrolysis. The hydrogen production cost is reduced with 0.7 and 0.55 EUR/kg H_2 when including the revenue from reserves for the two scenarios. **Figure 16** shows the capacity factor, where the inclusion of reserves reduces the optimal from 36 to 28 %. The capacity factor is at 53 and 43 % even with double CAPEX for the electrolysis, without and with reserves respectively.

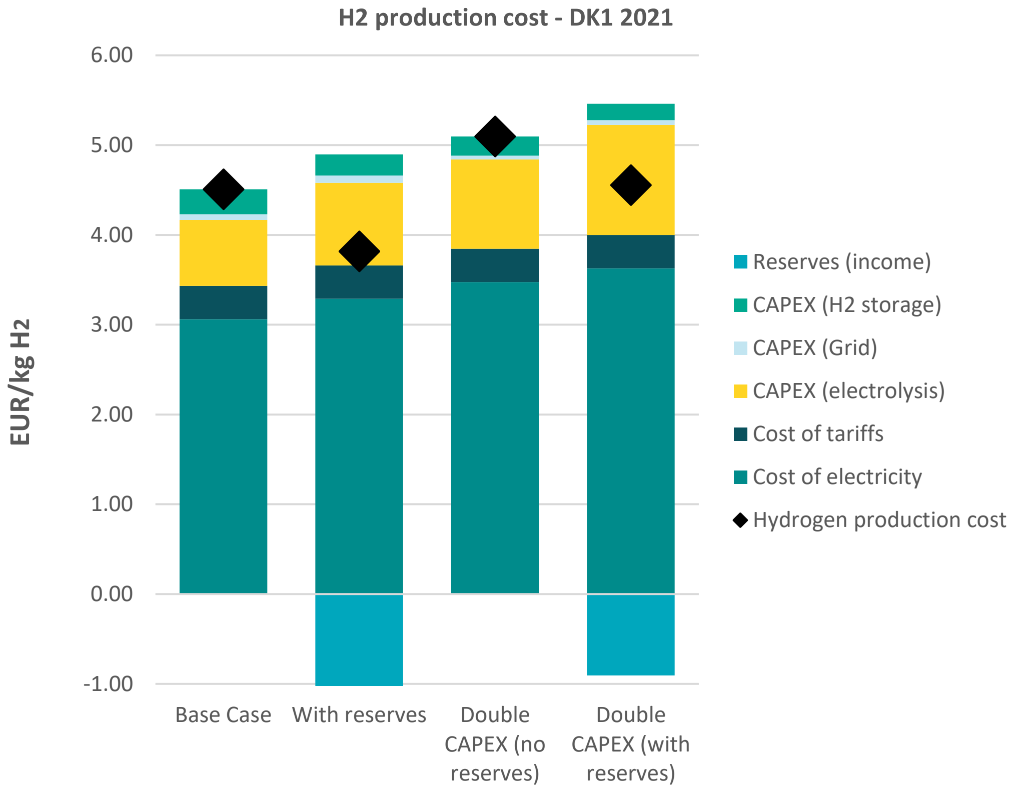


Figure 15: The resulting average cost of producing hydrogen for the electricity prices of 2021 for different scenarios, i.e. the reference without reserves, and the reference with reserves as well unlimited free hydrogen storage and double CAPEX for the electrolysis plant. The electrolysis can provide reserve and earn the prices shown in ***Figure 7****,* ***Figure 8*** *and* ***Figure 9****. For 2021 the constructed aFRR is used.*

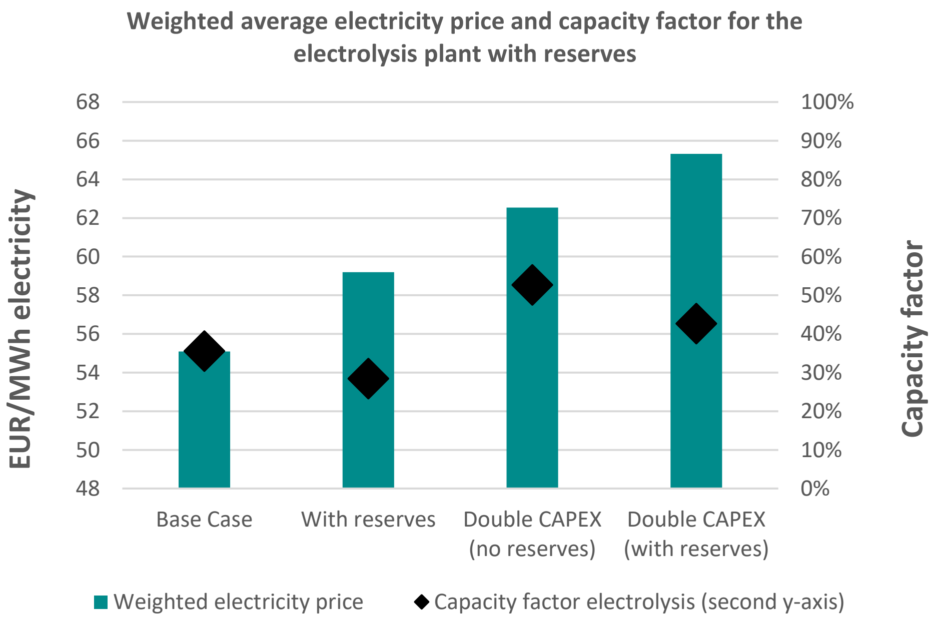


Figure 16: The resulting weighted average electricity price and capacity factor the electrolysis plant for the scenarios shown in ***Figure 15****.*

7. Discussion

The result of this report is purely to stress the potential value of flexibility, particularly in a future 100 % renewable electricity system. In a Danish system with less thermal power and much more wind and PV, the flexibility will be essential to enable a cost-effective transition. The value of the flexibility is difficult to quantify, and the numbers in this report should be taken with caution and the underlying assumptions taken into consideration. The method of this report could certainly be improved but would probably become more complex and difficult to follow. Hence, simplicity is favored above precision as the major uncertainty (future market prices) never will be eliminated anyway. However, some concerns are briefly addressed below.

The model does not include the energy activation market as this adds to the issue of having perfect foresight. The energy activation markets could impact the hydrogen production cost if other units set a marginal price higher than the one for the electrolysis plant, but to reflect reality this should be based on a given operational scenario for the current day of operation. It could be modelled as post-treatment of the result using historical imbalance prices but has not been prioritized. Similarly, counter trade (especially between DK1 and Germany) could also be considered, as the consumption can be 'sold' as downregulation and thereby withheld from the day-ahead market to achieve lower electricity prices. The current market design for counter trade is proposed to be changed and is therefore not included.

The model does not include any costs associated with dynamic operation or actual activation of reserves for electrolyzers as this is an unknown parameter. It should not be neglected as increased maintenance and shortened lifetime of the cells is expected if the electricity consumption is continuously shifted. It might vary for different electrolysis technologies. As might the regulating capabilities, particularly for the faster frequency reserves.

Electrolyzers can provide reserves as a part of a portfolio, i.e. as a hybrid plant together with renewables and a battery. For symmetric reserves this can be a benefit as the different technologies can cover a single regulating direction, whichever is the most feasible. The possible plant constellations are many, and other scenarios could definitely be analyzed. Likewise, revenue from excess heat and other assumptions could also have been varied.

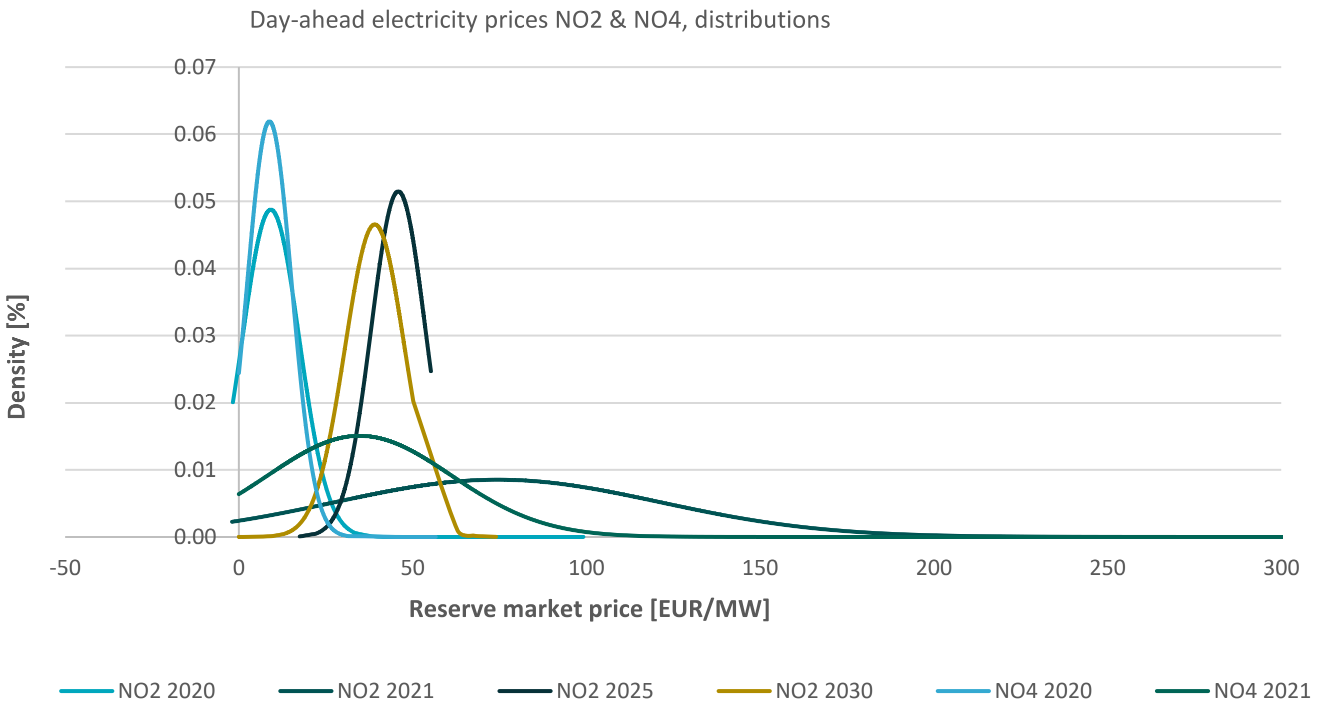
Again, it should also be mentioned that the perfect foresight and price taker assumptions are simplistic. One would need precise day-ahead forecasts and alike for the reserve markets to optimally exploit the value of the flexibility. The market prices for electricity and reserves used in this report should also be taken with caution, as the actual future supply and demand of implicit and explicit flexibility of the whole energy system will have an impact on the future market prices. Large changes to the market designs are also about to be implemented, and it is very difficult to say what the resulting prices will be.

However, the result of this report shows that the value of flexibility more than counters the costs of unlocking the flexibility, and that the optimal capacity factor in almost every scenario modelled is below 50 %, which means that the electrolysis capacity (in hydrogen output) should be more than double the average hourly hydrogen demand to minimize the average cost of producing hydrogen.

8. Appendix

8.1 Day-ahead electricity prices for Southern and Northern Norway, and Germany.

Historical prices for 2020 and 2021, and simulated prices for 2025 and 2030.



8.2 Hourly dynamics of the model

In the figures below, the hourly dynamics are shown for the first 100 hours of a modelled year. The result in **Figure 17** is for the scenario of 2021 without reserves, while the results in **Figure 18**, **Figure 19**, **Figure 20** and **Figure 21** are for the reference scenario of 2021 with reserves.

The invested electrolysis capacity in the scenarios without and with reserves are 47 and 59 MW (electricity input) to meet a fixed hourly hydrogen demand of 10 MW, respectively. Both with slightly above 500 MWh of hydrogen storage.

As seen in the below figures, implicit flexibility is visible as the lower day-ahead prices is correlated with electricity consumption and vice versa. For **Figure 18** it is not as correlated, as the capacity payment for the reserves can shift the overall cheapest hydrogen production cost to other hours. When symmetric reserves are sold, the consumption is also reduced compared to periods with asymmetric reserve provision.

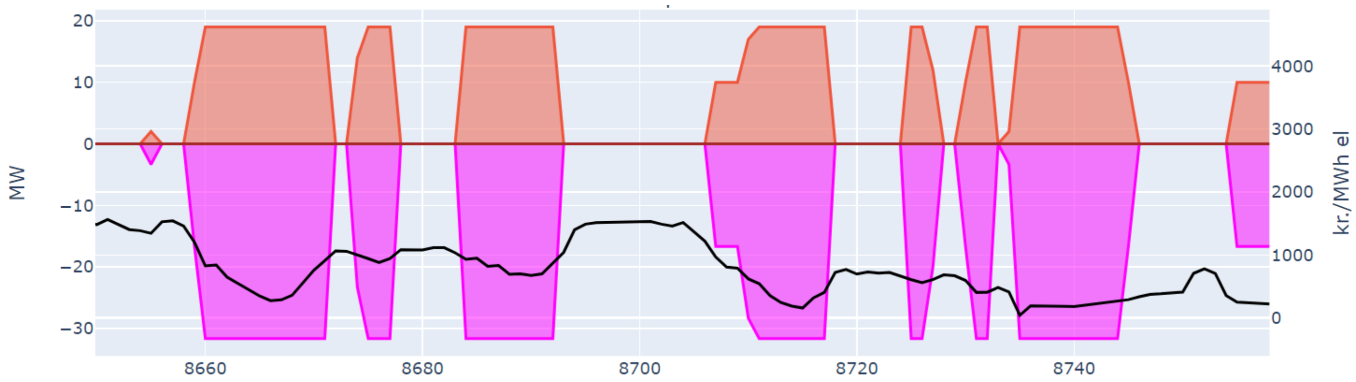


Figure 17*: The pink is the electricity consumption for the electrolysis, and the orange is the hydrogen ouput. The black line is the day-ahead electricity price. The hourly dynamics are shown for approximately the last 100 hours of the year. The scenario is 2021 without reserves.*

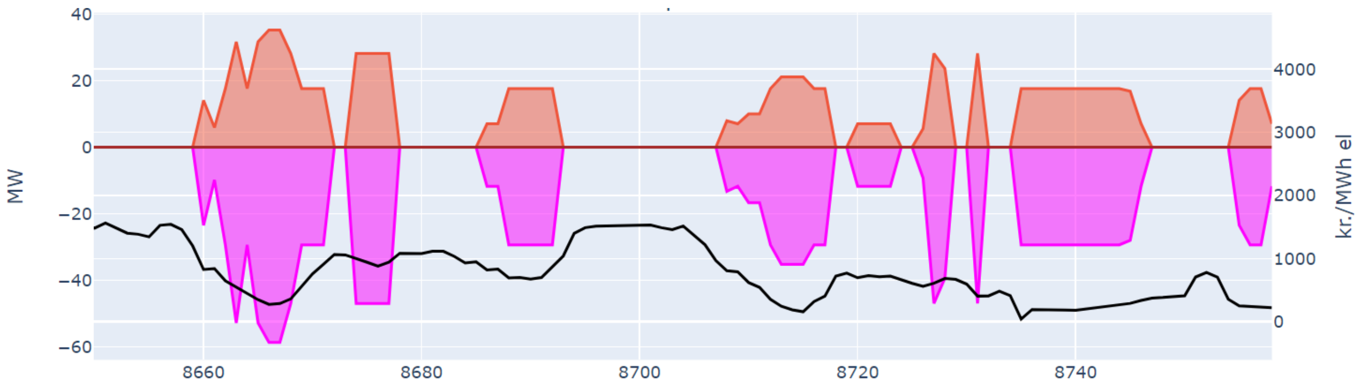


Figure 18*: The pink is the electricity consumption for the electrolysis, and the orange is the hydrogen ouput. The black line is the day-ahead electricity price. The hourly dynamics are shown for approximately the last 100 hours of the year. The scenario is 2021 with reserves.*

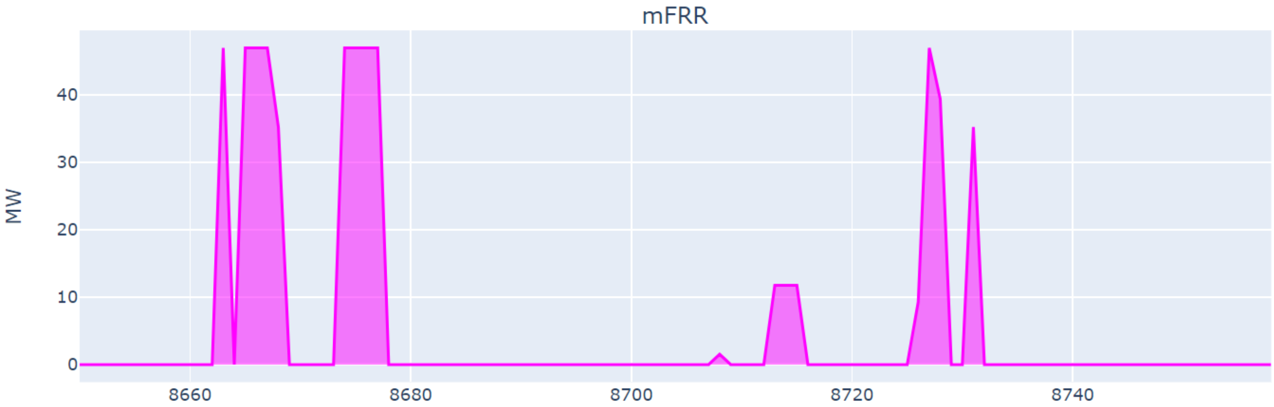


Figure 19: The pink is the sold mFRR reserve capacity (asymmetric for upwards). The hourly dynamics are shown for approximately the last 100 hours of the year. The scenario is 2021 with reserves. 80 % of 59 MW (~47 MW) electrolysis capacity can be provided.

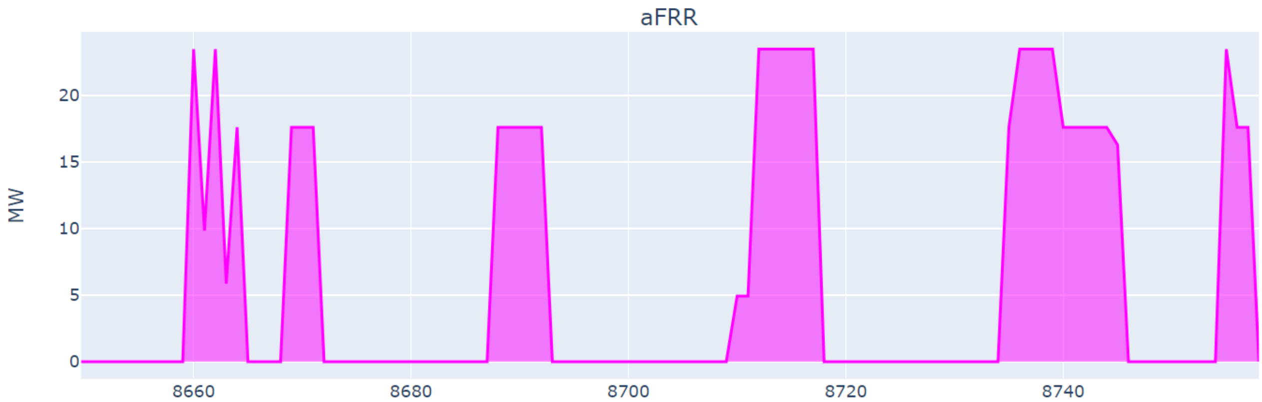


Figure 20: The pink is the sold aFRR reserve capacity (symmetric). The hourly dynamics are shown for approximately the last 100 hours of the year. The scenario is 2021 with reserves. 40 % of 59 MW (~24 MW) of electrolysis capacity can be provided.

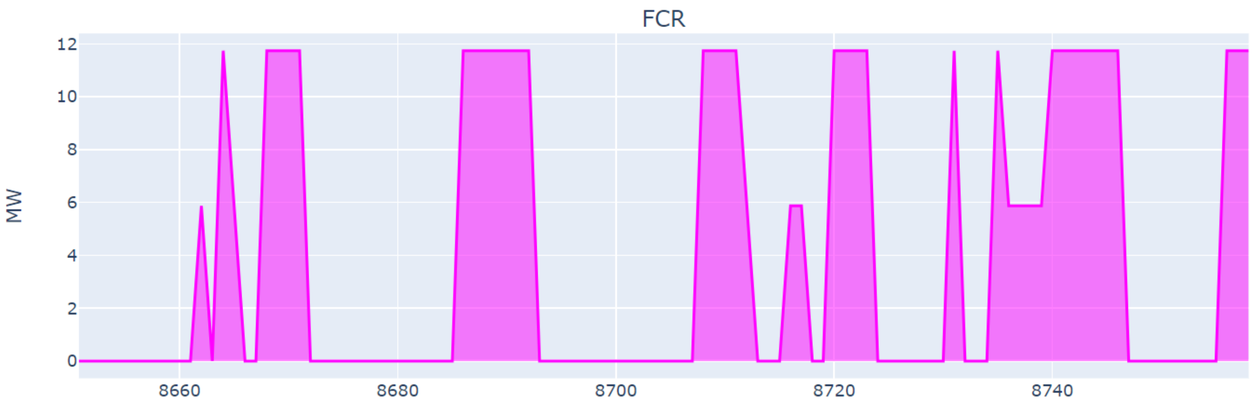


Figure 21: The pink is the sold FCR reserve capacity (symmetric). The hourly dynamics are shown for approximately the last 100 hours of the year. The scenario is 2021 with reserves. 20 % of 59 MW (~12 MW) of electrolysis capacity can be provided.