PTX IN DENMARK BEFORE 2030

Short term potential of PtX in Denmark from a system perspective

April 2019

Dok. 18/07002-9

ENERGINET

Content

Part one – Introduction and summary

1. Introduction

In Denmark the transition to renewable energy has already been underway for several decades. There has been a focus on exploiting wind and biomass for electricity and heat production since the 1980s. Approx. two-thirds (64 per cent in 2017) of the electricity supply in Denmark is currently based on renewable energy (RE) – 45 per cent from wind and solar power. In relation to the total energy consumption in Denmark, the share from RE is a little more modest at about one third (34 per cent in 2017). The transition to 100 per cent renewable energy over the next few decades will be a large and complex task, especially since many of the easy gains have already been made. Energinet's regular long-term energy system analyses, and the analyses of other players, have pointed to electrolysis as a potential key element in the transformation of the entire energy system for many years, but have also assessed that it will probably only have an impact of significance after 2030.

Energinet's latest long-term analysis, 'System perspective 2035'[1] from March 2018, includes comprehensive energy system analyses of the long-term potential for PtX in Denmark. The analysis suggests that PtX – the conversion of renewable electricity production via electrolysis into hydrogen, and further processing into gaseous and liquid fuels etc. – is expected to be a key and essential element in a cost-effective transition to a clean, renewable energy supply. The analysis also shows that Denmark has several strengths in relation to PtX, and that PtX can compete directly with fossil fuel alternatives in Denmark in 2035 in several scenarios. However, the analysis also suggests that there may be a willingness to pay a premium for the green PtX product, which could make PtX relevant earlier than this.

During the past year, several players have shown specific interest in PtX projects in Denmark already during the 2020s. Given its role as the electricity and gas system operator, Energinet needs to identify the initiatives it should begin preparations for, so that the electricity and gas systems are ready to embrace this development. This could involve ensuring holistic planning is undertaken for both the electricity and gas systems, interdisciplinary and long-term grid planning for the electricity and gas infrastructure, and the development of flexible market frameworks. It applies not only to the Danish systems, but also to integration across national borders. All elements that are important to ensure an efficient green transition for the entire energy system.

1.1 Purpose

Over the past year, Energinet has intensified its dialogue with potential PtX players, to gain a better understanding of when and to what extent PtX projects can be expected to emerge in the Danish energy context, and how Energinet can facilitate these developments as the electricity and gas system operator. The analysis in this report is based on this dialogue and seeks to identify: Whether PtX could become a reality in Denmark in the short term, what the immediate barriers seems to be, and how PtX projects in Denmark, can be expected to connect to the electricity and gas system.

This analysis can thus form the basis for further dialogue with the players and the work of identifying system possibilities and consequences in a timely manner, as well as market and regulatory needs and initiatives to remove barriers to this new kind of fully flexible and interruptible electricity consumption.

Chapters 1 and 2 – introduction and summary – comprise the first part of the report, introducing the PtX topic in a Danish context and summarising the results of the background analysis. The second part (Chapters 3-5) contains the

[1] www.en.energinet.dk/systemperspective2035

background analysis, which looks at various connection models for PtX, assesses the economic rationale for PtX and provides some illustrative case examples in Chapter 5.

1.2 Background

Many analyses indicate that a comprehensive electrification of the various energy systems through ‘sector coupling’ is central. Space heating can be supplied energy efficiently using electric heat pumps, and electricity – where it is practicable – is often the most energy efficient and cleanest energy source for the transport sector. At the same time, power generation from the wind and sun is already the cheapest way to produce renewable energy. And these are mature, commercial technologies that are implementable and scalable throughout most of the world. With the considerable reduction in prices seen in recent years, renewable wind and solar electricity generation is gaining ground globally – particularly in northwest Europe, where the proportion of electricity generation from the wind and sun is already high, and is expected to rise significantly in the coming years.

As Figure 1.1 shows, the proportion of electricity consumption from wind and solar power in several Denmark’s ‘North Sea neighbours’ is expected to increase from approx. 20 per cent today, to about 70 per cent in 2040 in the most ambitious scenario: Global Climate Action (GCA 2040)[2]. The proportion will already be around 50 per cent in 2030 in the least ambitious scenario: Sustainable Transition (ST 2030). Historically, efficient system integration with neighbouring countries has been key to integrating Danish wind power generation. Given the rapidly increasing volumes of fluctuating electricity generation throughout northwest Europe, there continues to be a great need for a strong electricity infrastructure, within each country and across borders. However, traditional electricity infrastructure cannot stand alone when such large proportions of fluctuating wind and solar power need to be integrated. There is a need to couple a large portion of electricity production to sec-tors such as heating and transport, and allow it to be allocated and utilised with price flexibility. Primarily, in order to effectively replace fossil fuels in the heating and transport sectors with cheap and abundant renewable energy from wind and solar power, but also to effectively balance the electricity system.

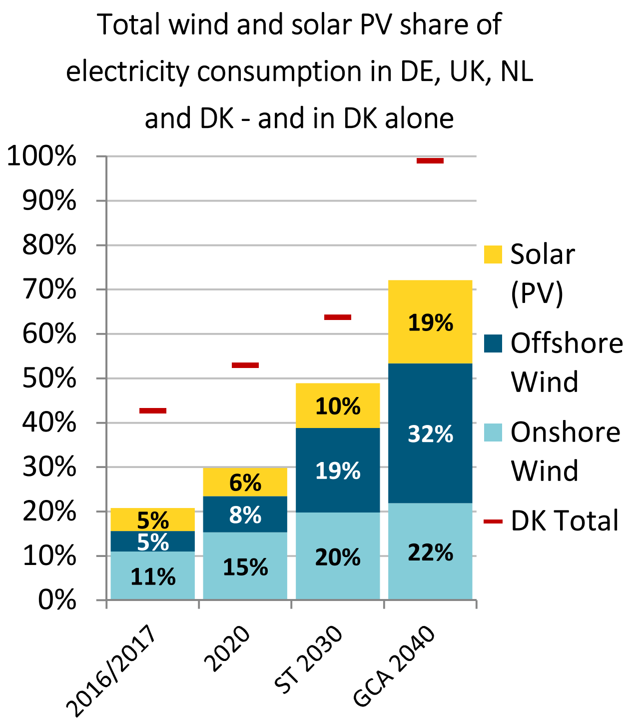


Figure 1.1

There is great potential in such a sector coupling and electrification. Electricity consumption currently accounts for only about 20 per cent of final energy consumption in Europe. An analysis[3] from Eurelectric – the European electricity industry’s special interest organisation – shows that it is possible up to 2050 to raise the direct electricity consumption in Europe to between approx. 40-60 per cent of the total final energy consumption. Direct electricity consumption is defined here as all the classic electricity consumption, as well as the direct electricity consumption in other sectors, such as heating (heat pumps, electric kettles etc.) and transport (electric motors, powered either by batteries or

[2] The TSO cooperation organisations – ENTSO-E (electricity) and ENTSOG (gas) – have set forth three scenarios in connection with the Ten Year Network Development Plan (TYNDP) which span the likely outcomes for development of the European energy system towards 2030 and 2040.

[3] Decarbonisation pathways – European economy: EU electrification and decarbonisation scenario modelling. Eurelectric, 2018.

overhead lines). Conversely, the analysis from Eurelectric shows that 40-60 per cent of the energy consumption cannot be converted to direct electricity consumption even in 2050. This energy consumption must be met by other fuels. In particular, there will presumably continue to be a large need for liquid and gaseous fuels in 2050, in sectors such as shipping, air traffic, heavy transport, industry, backup power generation etc. Since the entire energy sector has to transition to renewable energy, these fuels will also have to be green. The conversion of renewable electricity into chemically bound energy – PtX – can play a key role in this area. Sector coupling – in part through PtX – has also recently become a hot topic in European energy and climate policy. At the European level, the often very separated electricity and gas sectors have also started to communicate much more together, about cooperation in relation to PtX as one area.[4]

1.3 PtX – the flexible building block for the RE-based energy system

The analysis focuses on further processing renewable energy production via electrolysis to produce hydrogen, synthetic fuels (both liquid and gaseous) and synthetic chemicals. These processing operations are generally referred to as Power-to-X or PtX. This report uses PtX to refer to: Electrolysis, Power-to-Gas (PtG) and Power-to-Liquids (PtL).

Examples of PtX products include:

- Hydrogen. This can be used directly for heating and electricity generation (e.g. in CHP plants), in the transport sector (e.g. in fuel cells) and as a chemical commodity (e.g. at refineries). It may also be possible to mix a small amount into the natural gas grid. Hydrogen is produced through the electrolysis of water, which is a common first process step for production of the following PtX products.
- Synthetic methane. This can be fed directly into the natural gas grid and be used for the same purposes as natural gas. This production requires a CO_2 source. The process is often referred to as Power-to-Gas (PtG).
- Synthetic liquid fuels. E.g. methanol, petrol, kerosene (jet fuel), diesel and gas oil. These can be used for the same purposes as the corresponding fossil fuel products. This production requires a CO_2 source. The process is sometimes referred to as Power-to-Liquids (PtL).
- Ammonia. A basic ingredient in artificial fertilisers. Ammonia can also be used as an energy carrier for hydrogen, or directly as fuel. Its production does not require a CO_2 source, but only nitrogen, taken directly from the air. Since the introduction of CO_2 reduction targets for international shipping in 2018, there has been a great push from the major players to develop electrolysis-based ammonia as a CO_2-free propellant for shipping.

PtX (electrolysis/PtG) has been a key part of the long-term energy analyses for a renewable energy-based energy system for many years. The technology for producing hydrogen via electrolysis of water has been known for over 100 years. Electrolysis makes it possible to flexibly convert electricity into chemically bound energy, which is much cheaper to store and transport over long distances than electricity, so that it can be used where and when there is a need for energy. It has thus been long known that highly flexible, interruptible electrolysis is a good match for wind and solar power generation, inflexibly produced when the wind is blowing and the sun is shining.

Electrolysis is a flexible off-take for the electricity system that can collect and transform wind and solar power generated at times when it is plentiful and cheap – while also allowing the expensive, scarce and sought-after energy to be used for other purposes. Such flexible and interruptible electricity consumption thus also has the potential to

4 See also case 3 in section 5.3 about greater cooperation between the electricity and gas sectors in Europe in relation to PtG/PtX.

improve the utilisation of the electricity infrastructure. The potential is very great, but the cost of both the electrolysis technology and the renewable electricity to power the electrolysis has been too high to date.
6

2. Summary

Energinet sees sector coupling via PtX as an important element of the future energy system. It is therefore important that PtX technology is used in a way that supports an efficient general transition, utilising the potential of the electricity and gas infrastructure in the best possible way. PtX holds potential in relation to the conversion and transmission of large volumes of renewable electricity, and could therefore play a major role in optimising the expected expansion of the electricity and gas transmission infrastructure. This analysis seeks to identify whether electrolysis/PtX can be viable in Denmark in the short term (prior to 2030). Several general financial calculations have been made in the analysis, based on a simplified generic PtX-case, developed based on dialogue with several players who have shown specific interest in PtX projects in Denmark over the past year. Several archetypal models for how PtX systems could be connected to the renewable electricity expected to power them have also been developed for use in the calculations.

The analysis concludes that there is a realistic potential for establishing PtX systems in Denmark during the next 5-10 years. However, the analysis also shows that the regulations – including electricity tariffs – have a major impact on profitability and the choice of a connection model.

2.1 Why is electrolysis/PtX becoming economically interesting?

Hydrogen produced from the electrolysis of water has been a known technology for decades. Research has been done, and demonstration projects have been developed for electrolysis powered by renewable energy. Yet almost all current global hydrogen production, corresponding to about 70 times Denmark's electricity consumption, is created by separating hydrogen molecules from fossil natural gas, coal and oil. A good question to ask is therefore: 'What is going to make this pattern change over the next 5-10 years?'

A number of coinciding and mutually reinforcing trends in the energy sector in recent years may mean that electrolysis/PtX based on renewable electricity generation will see a breakthrough during the next few years.

- Falling costs for wind power and solar cells. The electricity price is a critical cost element for electrolysis. Electrolysis/PtX must be powered by renewable electricity, or facilitate the integration of more renewable electricity generation, to be of any value. Once wind and solar power have become the cheapest form of new electricity generation, electrolysis can be supplied with clean, green electricity at even lower prices.

- Large-scale industrialisation of electrolysis technology is beginning. While electrolysis-based hydrogen production has been a niche market for many years, for special purposes and small demonstration projects, the demand for electrolysis technology – both in terms of plant size and total amount – is now starting to accelerate, and the unit price has begun to fall correspondingly. Over the last five years, the largest demonstration projects have been electrolysis plants with capacities of up to approx. 1 MW. Shell is currently establishing a 10 MW electrolysis plant at a German refinery, and during the past year, two large German players have independently announced plans for 100 MW electrolysis plants in 2022 and 2023. In addition to green hydrogen production, the purpose of these 100 MW plants is to support the integration of German wind and solar power production into the German power grid. NEL – a Norwegian manufacturer of electrolysis plants for the global market – announced in 2018 that they will be expanding their annual production capacity for electrolysis plants by a factor of 10, to 360 MW a year, towards 2020. There has been a significant reduction in the MW price for electrolysis plants in recent years, and with the accelerating demand, these price reductions are expected to continue.

- Increased value of the green PtX product. An independent international market for green PtX products is taking shape. Green fuels have a market value significantly higher than the fossil fuel alternatives, including the price of the carbon emissions allowance. The market price for the first generation of biodiesel is currently around 1.6 times higher than the fossil diesel price. This higher price is driven partly by an increasing willingness to pay for the green product among consumers, and partly by European and national RE component requirements. With the revised RE directive, there will be more stringent requirements for RE fuels from 2021, and this is expected to increase demand for more advanced RE fuels, such as those made from renewable electricity using electrolysis/PtX. However, the way these revised European requirements are implemented in Danish legislation could have a significant impact on the value of green PtX products.

- Greater focus on the integration of wind and solar power in the electricity market and grid. With the increasing expansion of almost unsubsidised wind and solar power, in northwest Europe in particular, fluctuating renewable electricity generation is starting to account for such a large share of the electricity market that the settlement price for wind and solar power is coming under pressure. Manufacturers, developers and investors in wind and solar power therefore have a great interest in helping to integrate fluctuating electricity generation, in order to increase the value of green electricity production – even when it is abundant. It is also a challenge to expand the electricity infrastructure in time, so that the large quantities of green electricity can reach the locations where they are consumed. High volume, fully flexible and interruptible electricity consumption, such as electrolysis offers, can thus support better utilisation of the electricity infrastructure.

Investment costs in electrolysis plant have been the biggest barrier for many years, with the result that hydrogen from electrolysis has been reserved for niche markets and small demonstration projects. The above coinciding trends and the rapidly expanding market for electrolysis/PtX mean that the already significant cost reductions for electrolysis/PtX technology are expected to continue in the coming years. Investment costs (CAPEX) for electrolysis/PtX are not the focus of this report, and have been treated as an external given factor in the analysis. The analysis has thus been based on the expected future technology prices published in the Danish Energy Agency's official technology catalogue[5]. However, faster than expected implementation of electrolysis/PtX would result in a faster reduction in the investment costs than anticipated, all else being equal.

2.2 The electricity tariff is of key significance to the profitability of electrolysis/PtX.

Although electrolysis/PtX plants are expensive, the input – the variable operating cost of the electricity consumption – is typically the largest cost item. Cheap renewable electricity is therefore crucial to the profitability of PtX. However, it is not simply the electricity price that is critical, but the total price for the electrolysis. Taxes and tariffs on electricity from the public power grid therefore also play a major role. Under current regulations, from 2022 – when the PSO is completely removed from the electricity bill, it will primarily be the transmission and distribution tariff that must be added to the raw electricity spot

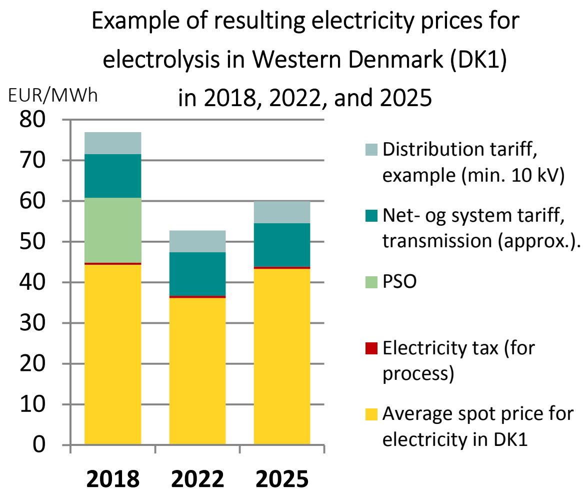


Figure 2.1

5 www.ens.dk/service/fremskrivninger-analyser-modeller/teknologikataloger

price to determine the total electricity price. Since electrolysis is viewed as a process, the electricity tax is only 0.54 EUR/MWh. Figure 2.1 shows an example of the resulting electricity price for electrolysis where the transmission tariff is set to 10.74 EUR/MWh and the distribution tariff to 5.37 EUR/MWh.

As shown in Figure 2.1, the total tariff for a small electrolysis plant connected to the upper part of the distribution network amounts to 16.1 EUR/MWh in the example. This is a significant part of the total electricity price for electrolysis, but much less than the tariffs and taxes on ordinary electricity consumption in households. Yet the size of the tariff is still able to have a major impact on the profitability of electrolysis/PtX, as illustrated in Figure 2.2. This shows an example of a duration curve, where the raw electricity spot prices for each of the 8,760 hours in the year have been sorted from highest to lowest. Since the final electricity price for the electrolysis is essentially the only variable (marginal) cost of electrolysis/PtX, electrolysis operates up to the total electricity price where the sales price for the hydrogen produced exactly covers the costs of producing it. The electricity price at which electrolysis is switched off is called the ceiling price, and is shown on Figure 2.2 as black dotted lines. The ceiling price in the example is 53.7 EUR/MWh for the total electricity price. This corresponds to the upper dotted line, where the tariff has been set to 0 EUR/MWh.[6] At a tariff of 16.1 EUR/MWh, the ceiling price corresponds to an electricity spot price of 37.6 EUR/MWh (the lower black dotted line), such that the total electricity price is still 53.7 EUR/MWh.

Electrolysis only earns money to cover fixed costs such as depreciation on plant and interest – a contribution margin – when the electricity price is lower than the ceiling price. This is illustrated by the blue areas in the figure. The contribution margin with a tariff of 0 EUR/MWh is thus area A + B, and the contribution margin with a total tariff of 16.1 EUR/MWh is area B. In this example, the contribution margin without a tariff (area A + B) is about four times larger than the contribution margin with a total tariff of 16.1 EUR/MWh (area B). The example thus shows how sensitive the profitability of electrolysis/PtX is in relation to the total electricity price – both the raw electricity spot price and the electricity tariffs. The point is not that electricity tariffs should simply be removed, but rather that as fully price-flexible and interruptible electricity consumption – which also supports the electrification of the energy system and the integration of renewable electricity generation – begins to become available, there will be a greater need for a tariff structure with more tariff products to match different needs for security of supply.

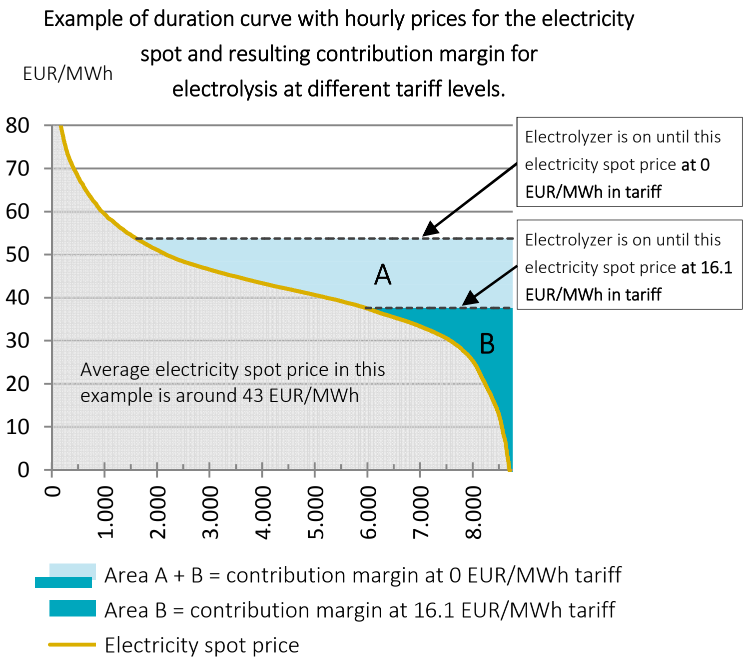


Figure 2.2

The analyses have been further explored in Chapter 4, in which several example calculations for profitability for PtX at various electricity prices and tariff levels have been performed.

6 The example in Figure 2.2 disregards the electricity tax of 0.54

2.3 Connection models for PtX

In order to reduce the tariff and tax costs, which have a major impact on the profitability of electrolysis/PtX, the players have an economic incentive to set up electrolysis plants at the same location as the renewable electricity generation source, 'behind the meter'. This is basically the same principle that applies when private solar cell owners save electricity taxes and tariffs on their electricity consumption that they generate at the same time. How the electrolysis/PtX is connected to the electricity generation source can also have an impact on how green the final product is perceived to be – and hence its sales value. The choice of connection model for electrolysis/PtX and thus implicitly, the geographical location, can also have a significant impact on the interplay between and planning of the electricity and gas infrastructure. In Chapter 3 of the analysis, several archetypal connection models have been prepared, described in detail and discussed. The connection models are used for the example calculations in Chapter 4, but are also intended as a model frame of reference for the ongoing work with – and dialogue concerning – the role of PtX in the interconnected Danish energy system.

In this summary, only the two general connection models will be highlighted: the offsite and onsite models. The models are based on wind/solar power generation, as the basic argument for PtX in Denmark is to utilise the abundant natural resources and integrate the cheap renewable electricity generation from wind and sun. The models are also based on PtX production of either gaseous methane or liquid methanol, i.e. PtX products that require a CO_2 source. For the pure production of hydrogen – or ammonia, where nitrogen can be extracted directly from the air in a relatively simple and inexpensive manner – the model would be simpler, as connection to a CO_2 source would not be necessary.

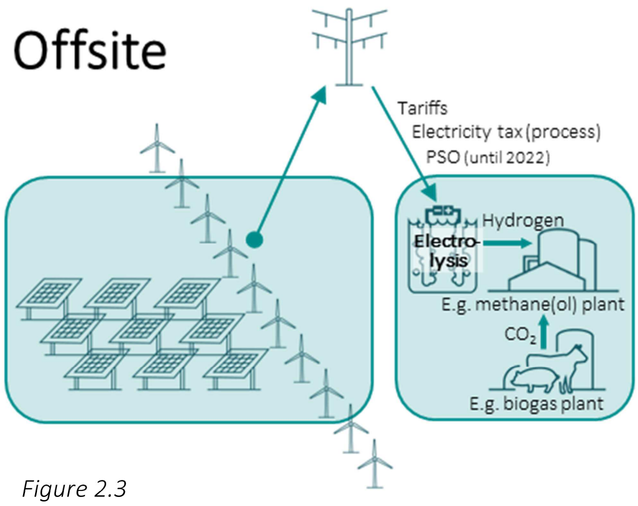


Figure 2.3

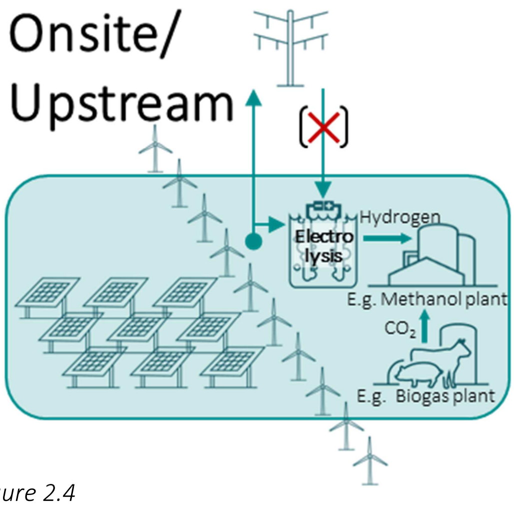


Figure 2.4

In the offsite model (Figure 2.3), all electricity consumption for PtX is drawn from the public power grid. Wind and solar power generation is located where there is space and the right natural resources. Electrolysis and the methane/methanol plant (for example) are located where there is a CO_2 source, storage capacity, demand and/or possibly demand for the by-products from the electrolysis process, such as surplus heat and oxygen. This model seems to be the most flexible in terms of finding locations with synergies in relation to PtX production – and hence also the model with the greatest potential for upscaling. Since the entire electricity consumption is drawn from the grid, this model is very sensitive to the tariff and tax structure, as shown in the previous section. The model has the added challenge that it can be more difficult to document/explain the RE component in the final product, when all the power is drawn from the electricity mix in the public power grid.

In the onsite model (Figure 2.4), the electrolysis is placed ‘behind the meter’, so that it can draw much of its electricity consumption from its own local wind/solar production, and thereby save tariffs. In relation to the electricity system, it will normally be an advantage to have electrolysis located close to the fluctuating electricity generation, as this places less demands on the power grid. However, finding suitable locations and exploiting synergies will be significantly more difficult if the electrolysis plant must be placed in exactly the same location as the renewable electricity generation due to private investor factors. It will be easier under the onsite model to document the RE component in the final product, as much of the power comes from the local wind/solar power generation. The upstream model is a variation on the onsite model, under which no electricity is imported from the public power grid (illustrated by a red cross over electricity imports in Figure 2.4). All else being equal, the upstream model will lead to lower utilisation of the electrolysis plant, as the option of supplementing with electricity from the public grid for electrolysis in periods of low production from the local wind and solar plants is not exploited. However, the upstream model makes it very simple to document that all electricity consumption for the electrolysis is RE from the local wind/solar plant.

Section 3.1.5 also describes examples of onsite variations, where the electrolysis is still placed ‘behind the meter’ at the same location as the wind/solar plant, but where the connection to the CO_2 source etc. is via a private hydrogen or CO_2 pipe. This allows the plant to bypass the prohibition in the Danish Electricity Supply Act against establishing private electricity connections between separate locations that are serviced by the public electricity system. Hydrogen and CO_2 infrastructure might easily be an appropriate solution in some cases, but this should ideally be based on what is most cost-effective for society. The advantages of this new type of unregulated infrastructure between locations also raises the political question of who should own such infrastructure, and how equal access for everyone can be ensured.

The archetypal connection models in Chapter 3 have primarily been developed as a tool for further dialogue and analysis. However, when viewed together with the example calculations in Chapter 4, it becomes clear that if there is no tariff and tax structure which supports very price sensitive and interruptible electricity consumption – such as electrolysis/PtX, there is a significant risk of less than optimal utilisation or creative solutions to get ‘behind the meter’. This could result in inefficient use of the electricity and gas infrastructure, and the full macroeconomic and transformative potential of electrolysis/PtX being reduced or delayed.[7]

2.4 Potential for hedging wind and solar power prices using electrolysis/PtX

As shown in the previous section and explained step-by-step with the sample calculations in Chapter 4, tariffs can have a significant impact on the profitability of PtX, as they can represent a significant part of the final electricity price. Yet it is still the raw electricity price that has the greatest impact. Despite all kinds of advanced model analyses, it is still notoriously difficult to predict future electricity prices because so many factors – regulatory, macroeconomic and system-related – come into play. The example calculations in Chapter 4 therefore conclude with several sensitivity analyses on the ‘raw’ electricity price.

7 The national implementation of the revised RE directive, regarding how PtX products may be included in the required fuel RE component and fulfilling RE targets in the transport sector, could also have a major impact on how quickly PtX will become commercially viable in Denmark. This regulatory aspect is not discussed further in this summary, but is covered in section 3.2.

The example calculations include investment in a renewable electricity generating plant consisting of 50 MW of onshore wind and 25 MW of large-scale solar power in 2025, along with 20 MW of electrolysis as the first stage of a PtX plant, which produces methanol in this example. The total investment in the PtX plant in the example calculations corresponds to about 40 per cent of the investment in the 75 MW wind and solar plant. The assumed average electricity price in 2025 (100 per cent on the x axis in Figure 2.5) can be varied by +/-25 per cent and +/-50 per cent, which is not unlikely from a historical perspective. For example, the average electricity spot price rose by approx. 50 per cent from around 27 EUR/MWh at the beginning of 2018 to around 40 EUR/MWh at the beginning of 2019.

The red line shows the profitability of the wind/solar plant alone. At the assumed electricity price (100%) in 2025, corresponding to an average settlement price of 41.9 EUR/MWh, the internal rate of return is about 9 per cent (real) without any government RE subsidy. This rate of return would appear to be commercially interesting for a mature technology with limited technical risks. But at an electricity price just 25 per cent lower (75%), the internal rate of return in the example calculation drops to a more investor critical level of around 4-5 per cent, and at an electricity price 50 per cent lower than expected, there is a negative rate of return on the RE facility. Conversely, the internal rate of return quickly rises to attractive double-digit percentages if the settlement price is higher than expected in 2025. For electrolysis/PtX alone, the situation is reversed. At the expected electricity price in 2025 (100%), the example calculation shows that the rate of return is only just acceptable – and only if the tariff is very low or the majority of production is onsite (behind the meter).[8] But at electricity prices lower than the expected level, the electrolysis/PtX plant begins to offer a decent return.

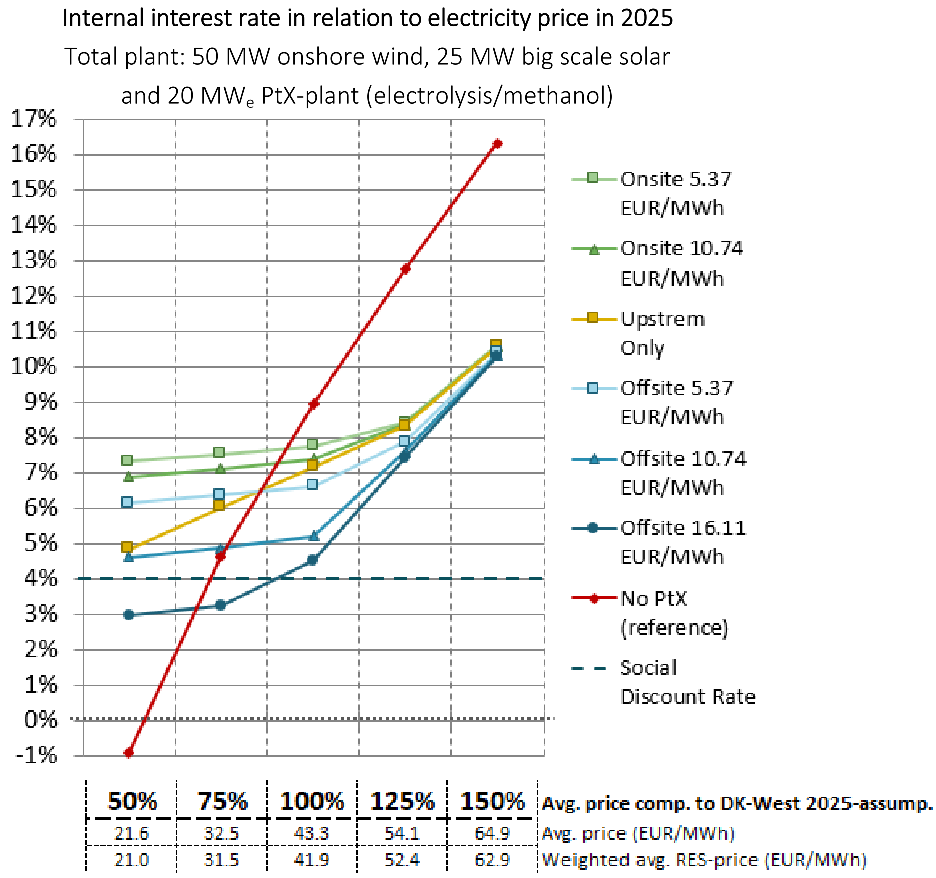


Figure 2.5

When the RE facility in the calculation example with the 50 MW wind and 25 MW solar power is combined with a PtX plant with 20 MW of electrolysis, the electricity price sensitivity looks completely different. The additional investment in PtX of about 40 per cent of the CAPEX for the wind/solar plant offers implicit hedging for the electricity price. It is a case of ‘what you lose on the swings, you make up for on the roundabouts’: If the electricity price is low, the PtX plant makes good money, and if the electricity price is high, the wind/solar plant earns well. The green, yellow and blue lines in Figure 2.5 show the internal rate of return, depending on the electricity price, for the combined RE/PtX project and various connection models and tariffs.

8 This cannot be seen from Figure 2.5. See section 4.5 and Figure 4.8 for more details.

The combination of RE and PtX generally offers significant hedging for the electricity price, with a much more stable return, irrespective of the price. While the internal rate of return in the combined RE/PtX project may not be remarkable for a private investor, it is at least positive for all selected sensitivities. Except for the offsite connection case with a 16.1 EUR/MWh tariff, the internal rate of return in the example calculation lies above the macroeconomic 4 per cent level, irrespective of the electricity price.

It is important to note that the example calculation in this analysis cannot be transferred to specific business cases. It is much too simple for this. However, the calculation example is generally deemed – under the given assumptions – to illustrate a conservative case, as a number of potential value elements and optimisation possibilities, which to varying degrees could be expected to be part of specific PtX projects, have not been included (see also section 4.3).

Yet the example calculations in Chapter 4, summarised in Figure 2.5 above, show that there is likely to be significant potential for hedging investments in wind and solar power using PtX. Hedging that could help to significantly reduce the electricity price risk associated with separate investments in wind and solar power. All else being equal, such hedging should lead to a lower return on capital requirement for such investments. Given that there are still very few large scale PtX plants, there continue to be many risks associated with being a first mover in this area, and these will probably increase the return on investment requirements of private investors. However, the hedging potential PtX offers means it is not inconceivable that large investors in renewable electricity generation from wind and solar power might be interested in contributing to the maturation, implementation and upscaling of PtX technology. The example calculations also suggest that even in the short term, PtX will be able to contribute to increasing flexible/interruptible electricity consumption, and hence also to macroeconomic resilience towards low electricity prices. PtX is a key technology for the transition away from fossil fuels. This analysis suggests that PtX may potentially be economically relevant even in the short term. It may therefore be relevant and timely even now to ensure that the regulatory framework and uncertainties in relation to this new technology in the energy system do not end up being barriers to investment in PtX projects in the short term. Energinet will use this analysis in the ongoing work of identifying the system-related possibilities and consequences of PtX in Denmark, and as a basis for further dialogue and collaboration with other players on the future development of PtX in Denmark – and how Energinet can accommodate this.

Part two – Background analysis

3. Connection models for PtX

PtX is a 'sector coupling technology' that builds bridges between different energy systems. As the name suggests, PtX can convert electricity to other (energy) products. How PtX relates to the electricity generated can have a major impact on both private investment profitability and perception of how green the final product is. The choice of connection model for PtX, and hence implicitly, the geographical location, can also have a major impact on how PtX affects the electricity and gas system in relation to infrastructure planning and market design. In this chapter, various archetypes for PtX connection models have therefore been prepared. These connection models provide the basis for further assessment of the profitability of PtX and influence of regulation on PtX. All connection models below are based on wind/solar power generation, as the basic argument for PtX in Denmark is to utilise the abundant natural resources and integrate the cheap renewable electricity generation from the wind and sun.

3.1.1 Offsite

The offsite model is characterised by the fact that the renewable electricity generation and electrolysis/PtX are placed geographically apart. The renewable electricity generation is located where there is space and natural resources for this. Similarly, the electrolysis plant and methane/methanol plant (for example) are located where there is a CO_2 source, storage capacity, demand and/or possibly a need for the other products of the electrolysis process, such as process heat and oxygen. This model would seem to be the best macroeconomically, and most suited to upscaling. The power grid is used to transport the entire electricity consumption. The profitability of this connection model is therefore very sensitive to the tariff level (analysed in more detail in Chapter 4). Use of this model will therefore probably be dependent on a tariff model that considers the costs/value of the high flexibility and interruptibility of electrolysis – and possibly also its geographical location value in the network. However, the model has the challenge that it can be more difficult to document/explain the RE component in the final product, when all the power is drawn from the electricity mix in the power grid (see also section 3.2).

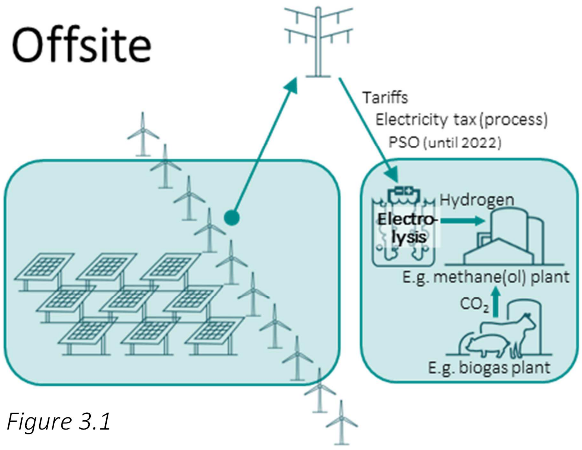


Figure 3.1

3.1.2 Onsite

The onsite model is characterised by the fact that the renewable electricity generation is at the same location as the electrolysis/PtX plant. The renewable electricity generation will typically have greater capacity than the electrolysis plant, as surplus electricity can always be sold to the grid. This means that 50-80 per cent of the electricity consumption for the electrolysis plant can typically be supplied directly from the local wind and solar power generation. Tariffs are thereby avoided for a large part of the electricity consumption, and it is easier to document RE component for the locally produced share of the electricity consumption for PtX.

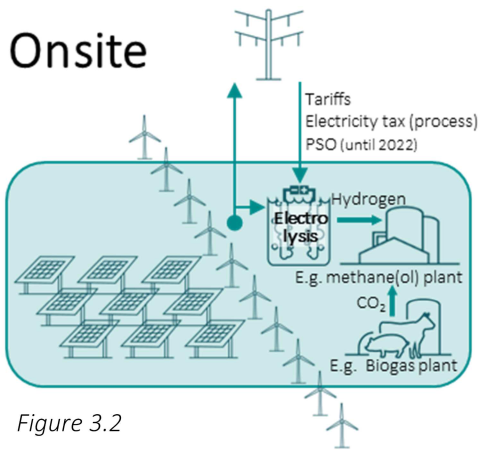


Figure 3.2

Depending on the tariff level, electricity will be imported from the grid during

Hours, when the electricity price (including tariff) is sufficiently low, and the onsite wind/solar plant is not supplying enough electricity to run the electrolysis plant at full capacity. Conversely, if the electricity price in the grid is higher than its value when used for electrolysis, the entire renewable electricity generation will be sold on the electricity market. The local wind and solar power generation will thus have two market channels: The larger electricity market and local electrolysis. This allows the renewable electricity generation to be sold where its value is highest. For the onsite model, it can still be difficult to document RE component in the final product during the hours where electricity is drawn from the grid.

3.1.3 Upstream

The upstream model is a variation of the onsite model rather than an independent archetype. Wind and solar power is again connected directly to the electrolysis plant 'behind the meter', and renewable electricity generation can be exported to the grid. But unlike the onsite model, electricity is never imported from the grid. The model is most effective when the wind/solar capacity is much higher than the electrolysis plant capacity, such that the electrolysis capacity can be fully utilised even during hours with limited renewable electricity generation. As with the onsite model, the entire electricity production is exported during hours when the electricity grid price is higher than its value if used in the electrolysis plant. The upstream model may have an even higher 'green value' than the connection models that import power from the grid, as it is easy to document that the final product is made using 100 per cent renewable and local electricity generation. Since the model is almost identical to the onsite model in terms of plant, the owner can presumably switch between an onsite and upstream model, depending on whether the final product from the upstream model has a 'green premium' or subsidy benefit that outweighs the less efficient utilisation of the electrolysis plant's capacity.

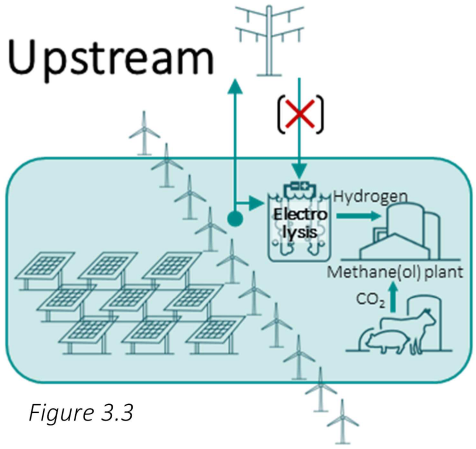


Figure 3.3

3.1.4 Off-grid

Like upstream, the off-grid model is also a variation on the onsite model. However, the model is a more striking variation, in that it has no connection to the grid whatsoever.

While it does allow the cost of a grid connection, possibly some minor electricity taxes and perhaps some hardware required for grid connection to be saved, this model has a major economic drawback. The fluctuating wind and solar power generated in the off-grid model can only be utilised for local electrolysis, leading either to: Too much downtime/waste of otherwise valuable wind/solar power, or many hours with low utilisation of an expensive PtX plant.

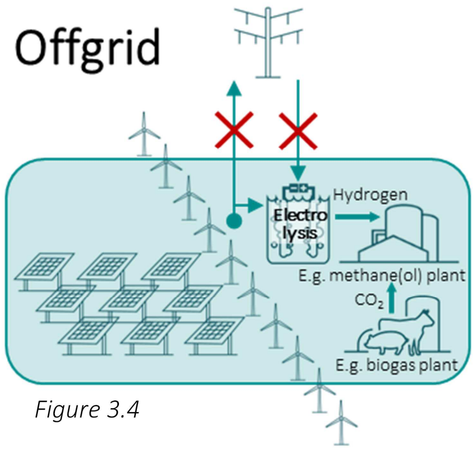


Figure 3.4

If being connected to the grid entails strict and cost-intensive regulation, this model can presumably be optimised considerably using hybrid renewable electricity generation, such that combinations of wind power, solar cells and batteries can result in a high number of full-load hours for the total plant. However, this is a costly initiative for the plant, and the value of the flexible electrolysis in the wider electricity system is also lost. For example, the electricity generation in the closed system will still go to the flexible electrolysis, even if there is a shortage of power and high electricity prices in the grid. In the short and medium term, this model is expected to almost only be relevant if the plant is located far away from the public power grid. The model also has no higher 'green value' than plant connected to the grid using the upstream model, where all PtX production also uses 100 per cent local RE.

3.1.5 Onsite variations with private infrastructure

In addition to the above archetype connection models for PtX, several variations on the onsite model can be mentioned which are based on one or more connections using private infrastructure between different geographical areas. These are called onsite variations, even though the locations are physically separated, because they are connected by private infrastructure. These variations can offer some of the same flexibility as the offsite model in relation to locations of the various components, while still allowing considerable savings for the players compared to using the public electricity infrastructure with the existing uniform tariff structure.

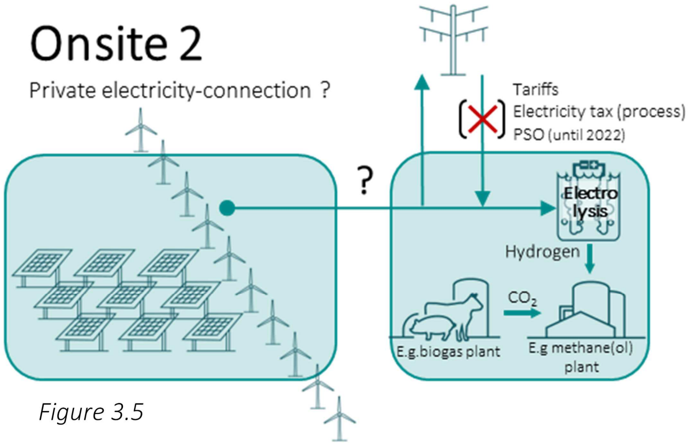


Figure 3.5

The examples on the right are not exhaustive, but simply show some of the ways connection models can be optimised to achieve the best value from a PtX project for the private investors – and in some cases for society also.

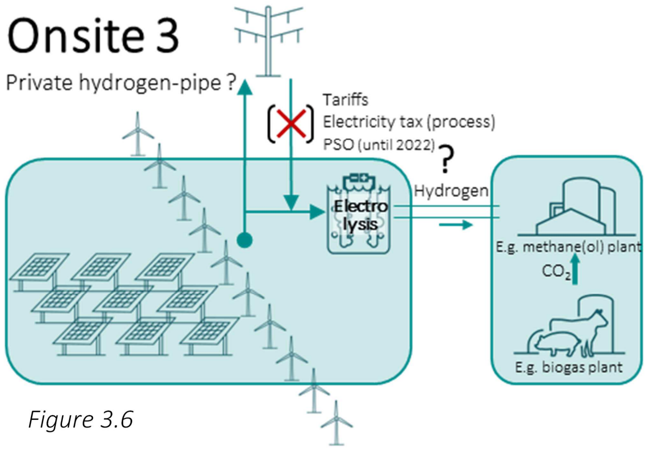


Figure 3.6

Infrastructure for electricity and natural gas (gas of methane quality) is regulated by the Danish Act on Electricity and Natural Gas Supply. It is rarely possible in Denmark, under the Act, to establish a private electricity connection between two geographically separate areas, as shown in Figure 3.5.[9] But there are no independent regulations governing infrastructure for gases other than gas of natural gas quality (including upgraded biogas). If you can obtain the local permits and comply with the requirements from the Danish Safety Technology Authority etc., it is possible to build private infrastructure for hydrogen, CO_2, oxygen, raw biogas etc. Some examples of this type of connection model are shown in Figures 3.6 and 3.7. There may therefore be alternative connection models that can be attractive to private investors (and possibly to society) compared to an offsite solution, where the full tariff is paid on all electricity consumption for the electrolysis. The potential of these alternative connection models raises the political question of whether there is a need to regulate infrastructure for gases other than natural gas (methane) etc.

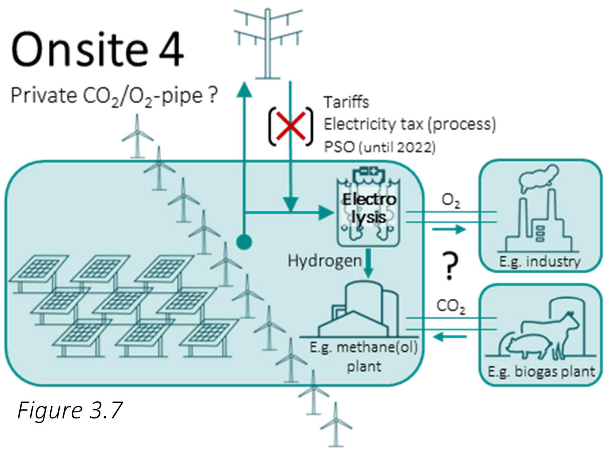


Figure 3.7

9 However, such connections are typically allowed/required for private collection grids, for example, between the various turbines in a wind farm, which span landholdings. A private shore landing, e.g. from an offshore wind project to a landholding on the shore may also be permitted.

All onsite variants can also be purely upstream (no partial offtake of electricity from the public grid). This can be relevant in relation to documenting the 'green value' of the final product, both in relation to end customers and the EU RE component requirements for transport fuels.

3.2 The RE directive and the impact of the connection model on the green value

This section relates to the revised RE directive[10]*, often called RED II, which was finally approved by the Council of the European Union on 11 December 2018. Please be aware that this section has been written based on the author's superficial interpretation of the relatively new directive text. It is the Danish Energy Agency that has responsibility for implementing the directive in Danish legislation. No guidelines to the directive are yet in place. The directive also allows significant freedom to Member States in several areas. The way the directive is implemented in Danish legislation can therefore be expected to have a major impact on the conditions for PtX etc. in Denmark.*

The calculation examples in Chapter 4 of the analysis are based on PtX being marketed to the transport sector, as this is seen as a high-value market. The high value of RE fuels in the transport sector is due in part to the specific requirements in the RE directive for the proportion of renewable energy in the transport sector, and the fact that the fuel quality directive sets specific obligations for including liquid or gaseous fuel based on biomass. The responsibility for adding biofuels lies with the companies which supply fuel to the transport sector.[11]

The current RE directive in force today only touches on the use of green hydrogen and other electrolysis-based RE fuels in general terms, and not specifically in relation to fulfilling targets in the transport sector. This means that it would be difficult to use PtX fuels for compliance with the obligations described above.

The revised RED II directive, which will apply from 2021, introduces the concept of *"renewable liquid and gaseous transport fuels of non-biological origin".*[12] In practice, this corresponds to 'RE electrofuels', with hydrogen from an electrolysis process providing the fuel energy content. The new RE directive sets rules for how these RE electrofuels may be used in relation to the RE obligations for the transport sector, and how the RE share must be substantiated. RE electrofuels 'only' count once in the new RE directive, whether liquid or gaseous – not twice like biogas (advanced biofuel).[13]

Another change is that it looks like it will be possible to count RE electrofuels when these are included as an intermediate product. This should probably be interpreted to mean that refineries will be able to count RE-based electrolysis hydrogen used in the process of producing conventional fuels such as petrol and diesel (see the case in section 5.1). The rationale is that green hydrogen for the process replaces hydrogen derived from conventional gas.

The extent to which electrolysis-based fuels can count towards fulfilling the RE requirements for transport depends on the RE share in the PtX product. This is calculated using the principle that the RE share in the electrolysis-based hydrogen corresponds to the average RE share in the national electricity supply two years before the PtX production

10 Link to the revised RE directive (RED II): https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG

11 In order to create a more market-based system, it is possible in Denmark, the Netherlands and the UK to meet one's own target by buying credits from other companies that have exceeded their targets. This is known as the biotickets scheme and can be described as a paper trading system where biofuels can be traded virtually, provided that it can be shown the transaction is based on an underlying physical product.

12 It is unclear whether the hydrogen produced from biomass-based electricity will fall under this definition or be regarded as a biofuel.

13 There is also an additional minimum requirement in RED II for an advanced biofuel component: 0.2 per cent in 2022, 1 per cent in 2025 and 3.5 per cent in 2030. However, individual Member States can exempt fuel suppliers who provide electrofuels from the obligation to have a minimum proportion of advanced biofuel, whereby the green value of RE electrofuels, e.g. via the sale of biotickets, can be expected to be half the value of advanced biofuels.

takes place.[14] This indicates that the choice of connection model in the above archetypes will have no impact on the RE energy content in the final product.

However, under article 27 of the directive, it is possible to disregard this basic principle and denote a PtX product as 100 per cent RE if one of the following conditions is met:

1. Direct connection to an RE facility with no connection to the public electricity grid, and the RE facility only commences operation at the same time as or after the PTX plant becomes operational. *This corresponds to the off-grid model.*

2. Direct connection to an RE facility with a connection to the public electricity grid, but where it can be documented that no electricity has been imported from the public grid during the production period for the given production batch. The same rule for commencing operation applies as in point 1 above. *This corresponds to the upstream model, or the onsite model during periods with no electricity imports from the public grid.*

3. Electricity imported from the public grid, if this has been produced from renewable energy sources and that the RE properties and all other relevant criteria have been demonstrated, such that the RE properties of this electricity are only applied once, and in only in one end-user sector. *This corresponds to the offsite model, but it is still unclear exactly what the documentation requirements will be.*

These additions must be seen as positive in relation to all the described archetypes, as they will make it possible for the final product to qualify as 100 per cent renewable energy, irrespective of the configuration used. At present, however, only points 1 and 2 are practicable, because their documentation is relatively simple. Point 3 above, using electricity from the public grid, will be subject to the requirement, under recital 90 in the RE directive, that a method be developed that ensures there is a temporal or geographical link between the renewable electricity generation the PtX producer owns or has a bilateral renewable electricity purchase agreement regarding, and the electricity consumption for fuel production. For example, RE fuels of non-biological origin (read 'electrolysis-based fuels') cannot be seen as fully renewable if they are produced at a time when the RE generation unit covered by the contract is not generating electricity. Another example is geographical congestion in the electricity grid. Fuels can only be fully renewable if both the electricity generation and fuel production facilities are located on the same side of a congestion point in the grid.

In practice, this 'congestion limitation' presumably means that point 3 above can only be fulfilled if the RE source and PtX system are located in the same electricity price zone, as a minimum. In addition, the requirement that electricity generation and electricity consumption for electrolysis supplied via the grid occur simultaneously will presumably require refinement to existing certificate models, as a minimum. It will presumably be relevant to look at whether there is any interest in, and it is possible, to establish a reliable national or European method that can be used to fulfil the documentation requirements in point 3 above in relation to an offsite connection for PtX. Conversely, the RE share in the Danish electricity supply was already 63.7 per cent in 2017, and is expected to rise dramatically in the coming years. If the RE share in the Danish electricity supply – understood as the renewable electricity production in proportion to electricity consumption – reaches around 100 per cent or more in the foreseeable future, there will be less need for this type of documentation scheme than in countries with a much smaller RE share.

14 The RE share in the electricity supply should be understood as the total renewable electricity generation in a Member State, divided by the gross electricity consumption in that Member State. For example, see article 7 of RED II or the Eurostat guide for RES-E (Renewable Share in Electricity): https://ec.europa.eu/eurostat/documents/38154/4956088/SHARES-2013-manual.pdf/6545be46-cacc-4e6d-baee-eceb99192d2f

The requirement in points 1 and 2 above, that the renewable electricity generation in an off-grid, onsite or upstream model may only commence operation at the same time or after the PtX facility does so, stems from the desire for the renewable electricity generation to be additional – such that the new electricity consumption for PtX does not simply lead to an increase in electricity generation based on fossil fuels. Developers of wind and solar power facilities therefore cannot simply prepare for a possible later onsite PtX plant at a new wind/solar location, if they want to make use of the exceptions in points 1 and 2 above. But again, if Denmark reaches an RE share in the electricity supply close to or above 100 per cent within a few years, this may not be as important in a Danish context. If it is always possible to 'fall back on' the general rule that the RE share in a PtX product follows the RE share in the Danish electricity supply two years previously, there are many onshore wind sites – both new and old – which it could potentially be of interest to combine with PtX in an onsite model, thereby saving tariffs on the locally generated electricity.

4. Economic potential for PtX in Denmark in the short term

There has been disagreement about the economic potential for PtX in international analyses and literature on the subject in recent years. The differences in the calculations typically depend on various price assumptions, plant configurations, and which value streams are included. Given great uncertainty in this area, it was deemed relevant to perform some general calculations on some generic cases, to gain insight into the economic potential for PtX projects in Denmark in the short term. This is relevant to be able to assess the need to adapt market design and influence infrastructure planning. In this chapter, some calculation examples will be presented and discussed, which include the general cost and value elements for PtX in Denmark in 2025.

4.1 Final electricity price is typically largest cost element for PtX

The electricity price is typically the most important cost element for PtX. The energy resource for PtX must therefore be cheap electricity generation, and preferably from renewable energy sources. In the Danish context, this will primarily mean electricity from wind and solar power generation. The calculations have used the expected hourly prices for electricity in Western Denmark (DK1) in 2025.[15] Given that it is the final electricity price for electrolysis that is critical, factors such as taxes and tariffs on electricity from the public electricity grid are also of key importance. For electrolysis in Denmark, the final price for electricity from the public grid consists of the following elements with the current tax and tariff structures:

- The market/spot price for electricity.
- Electricity tax. Electricity for electrolysis is only subject to process electricity tax, which is set to the EU's minimum rate of 0.54 EUR/MWh in Denmark. Therefore, the electricity tax itself only has little impact.
- PSO tariff. This will be gradually transferred from the electricity bill to the federal budget up until 2022. The PSO tariff will change from approx. 17.45 EUR/MWh in 2018 to 0 EUR/MWh in 2022.
- Grid and system tariffs: The transmission tariff is about 10.74 EUR/MWh. There is also a distribution tariff of about 2.68-6.71 EUR/MWh for connection to the distribution network (at 10 kV or 50/60 kV). The calculation example uses a sensitivity model with a total tariff of 16.1 EUR/MWh, which can illustrate connection at the distribution level.

15 Time series based on AF2018 (Analysis assumptions for Energinet 2018, from November 2018).

From 2022, when the PSO tariff has been phased out, it will essentially be only the grid and system tariff for transmission, and possibly the grid tariff for distribution, that must be added to the market price for electricity to get the final electricity price for the electrolysis. Figure 4.1 shows the composition of the final electricity price for electrolysis in Western Denmark (DK1), using electricity prices based on AF2018 and historical prices for 2018. The figure also shows resulting 'ceiling price' from the calculation example. The ceiling price shows how high the final electricity price can rise before electrolysis is 'switched off'. Figure 4.1 shows the final price as an annual average. Since the spot price varies considerably over the 8,760 hours during a year, the final electricity price can be less than the ceiling price for many hours over the year, even if the annual average is not. This is further explained in section 4.4. However, Figure 4.1 shows in general how the various elements of the final electricity price impact on whether the electrolysis will run.

Example of resulting electricity prices for electrolysis in western Denmark (DK1) in 2018, 2022 and 2025

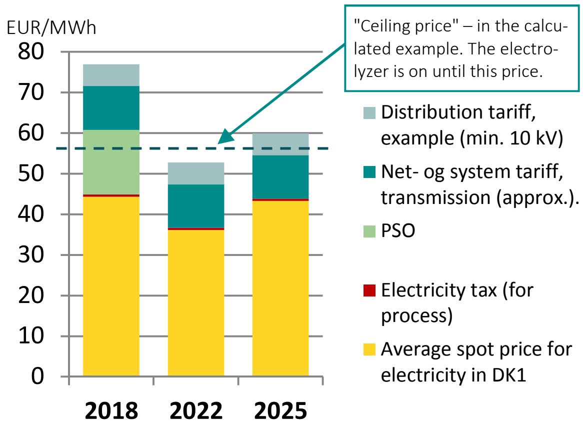


Figure 4.1

The efficiency for the total conversion describes the relationship between the final electricity price for electrolysis and the marginal production cost for the final product. The efficiency is therefore critical to the profitability, in the same way as the final electricity price. The calculation example uses a total efficiency of 60% (lower calorific value) from electrical input via electrolysis hydrogen to output as green methanol. This corresponds to the efficiency of the entire process in 2025, in line with the technology catalogue.

4.2 International market for green PtX product with significantly higher price

The selling price for the green final product is key to the profitability of PtX. It is not deemed to be realistic – in either the short or medium term – that PtX can compete directly with the fossil alternative (typically natural gas or oil) in terms of price. However, Energinet's 'System perspective 2035' analysis shows that in some European energy scenarios after 2030, PtX in Denmark – in the form of electricity to liquid fuels – will be able to compete directly with fossil oil (with the scenario's carbon price added). However, there is already a willingness to pay/market price for green fuel, which is far higher than the carbon price. This higher valuation for green fuel is partly driven by large energy consumers who wish to make their entire value chain green. In Europe, however, it is increasingly the European requirement to add an RE component to fuels used for transport that is setting the elevated price level for green fuels. For example, 1G biodiesel – made largely from palm oil – has had a market price 1.6 times the average diesel price in recent years under the current RE directive. In the revised RE directive, which takes effect in 2021, there is a higher target for the RE share in transport fuels, requirements concerning the share of advanced biofuels, and an upper limit for the share of 1G biofuels used in transport.[16] Under these more stringent new requirements, the price premium for green fuel is expected to remain at least at the current level.

4.2.1 Green methanol in the calculation example

In the calculation example below, green methanol is used as the final product. Methanol is a widely used commodity in the petrochemical industry. It is a primary ingredient in a wide variety of chemical products, and green methanol can also be directly added to petrol or used with modified diesel engines to fulfil the EU RE component requirements. Very

16 Article 25, which sets requirements for the share of RE for fuel suppliers.

similar to the way bioethanol is currently used in Danish petrol. Green methanol is also one of the PtX products that appears to receive much interest in the project analyses of Danish players over the past year. Some Danish players have reported that it is possible to secure a long term fixed-price agreement to supply green methanol at a price of around EUR 600/tonne at production site (approx. EUR 30/GJ), and at even higher prices on short-term contracts. This is compared to a spot price for fossil methanol in the range of EUR 300-400/tonne (EUR 15-20/GJ), which is at about the same price level as fossil petrol from a Danish refinery. The calculation example uses a slightly more conservative price for a long-term contract on green methanol of EUR 26.85/GJ (EUR 535/tonne).

Instead of producing methanol, as in the calculation example, another option could be to produce methane using a similar process and the same connection models as described in Chapter 3. However, it does not appear to be possible to obtain the same price for electrolysis-based green methane (gaseous) as can be obtained for electrolysis-based green methanol (liquid). If sufficient demand for gaseous RE fuels for transport arises, the selling price for electrolysis-based green methane may move closer to the price of electrolysis-based green methanol, as both fuels have the same value in relation to the European RE component requirement in fuels used for transport. A more detailed analysis of the various development paths for PtX in relation to the gas system will not be provided here. The calculation example could also be formulated for electrolysis-based ammonia, which is already a widely used chemical, e.g. in artificial fertilisers. Several players also highlight PtX ammonia as a promising climate-neutral fuel for applications such as shipping. PtX ammonia requires a slightly different – and simpler – setup, as it does not need a CO_2 source. Other players predict that clean, green hydrogen will increasingly become the final product for the transport sector and other purposes. Irrespective of the primary final product, the PtX sector coupling will predominantly be via hydrogen production from electrolysis using renewable electricity generation. The further processing that happens after the electrolysis, if any, is not central to the impact PtX will have on the electricity system. The purpose of the calculation example is to examine the potential in short term for a general PtX case in Denmark. The methanol case has been chosen for as calculation example here, because several commercial players have identified this as interesting in short term, and because it has been possible to give a qualified estimate of sales prices for green methanol on a long-term fixed-price contract.

4.3 Generic case profitability calculation for PtX in 2025

As just stated, the PtX product used in the calculation examples is green methanol, which it is assumed to be sold on a long-term contract at a fixed price EUR 26.85/GJ (at production site). Surplus CO_2 from upgrading biogas will be used as CO_2 source. The example is based on a 20 MW_{el} alkaline electrolysis plant. This technology and scale are already commercially available today. A methanol plant of a similar size is also assumed. The CO_2 consumption of a methanol plant of this size more or less matches the excess CO_2 from upgrading biogas at the medium-sized plants, that have been built around Denmark in recent years. The calculation examples also include calculations for a 75 MW RE facility, consisting of 50 MW onshore wind and 25 MW large scale solar power (field systems). In addition to the stand-alone PtX system (offsite), calculations have been made for onsite and upstream variations, in line with the connection models from Chapter 3, where the electricity consumption for electrolysis in the PtX plant takes place at the same location as the wind and solar power is generated. The prices and efficiencies for the technologies are based on the technology catalogue assumptions for 2025.[17] The reason that the calculation examples focus greatly on production

[17] However, a 25 per cent CAPEX reduction has been made for large scale solar cells in 2025. This brings the LCoE (Levelised Cost of Energy) for large scale solar cells down on par with the LCoE for onshore wind power in 2025. This has done been done to simplify the calculations, and avoid having to perform an independent optimisation of the relationship between the onshore wind and solar cells for each calculation variation, which would also make comparing the variants more unwieldy. In practice, for the vast majority of cases, this does not result in better profitability for PtX than if the calculation was performed using only an offshore wind facility. In fact the opposite is the case. The calculations have not simply been performed using onshore wind power alone, due to the desire to examine whether the upstream or off-grid models (which benefit most from the complimentary nature of wind and sun) might be essentially competitive with the other models if the large scale solar cells had an LCoE equivalent to onshore wind. In the underlying calculations, it is only at the lowest electricity price scenarios (50%) and for off-grid models, that a

price of wind and solar power, and not just the expected price of electricity from the grid, is that PtX is only meaningful and of interest when it can be predominantly driven by wind and solar power[18]. The international analyses that are critical regarding the potential of PtX, frequently use significantly higher LCoE prices for wind and solar power, than those used in this analysis.

Electricity prices for each hour of 2025 have been calculated based on AF2018 (Analysis assumptions for Energinet 2018). The calculation is based on a placement in Western Denmark (DK1) where the majorities of new biogas plants and onshore wind farms are located. Please note that the calculation examples are based on simplified assumptions, and only the most important cost and income elements have been included. For example, it has simply been assumed that surplus CO_2 from upgrading biogas can be obtained free of charge. Conversely, no value has been assigned to surplus heat and oxygen produced from the PtX processes. The value of having the electrolysis process participate in markets for regulating power and ancillary services has also not been included. It is also likely that profitability can be optimised significantly in calculations for specific projects by establishing 'buffer stocks' for hydrogen, renewable electricity generation, etc.

The purpose of the calculation examples is not to optimise all variables for a specific case, but merely to perform a rough calculation to show whether a simple, non-optimised PtX setup is close to profitability in Denmark in the short term. A series of sensitivity analyses also illustrate the impact of various tariff levels and electricity price assumptions on different connection models.

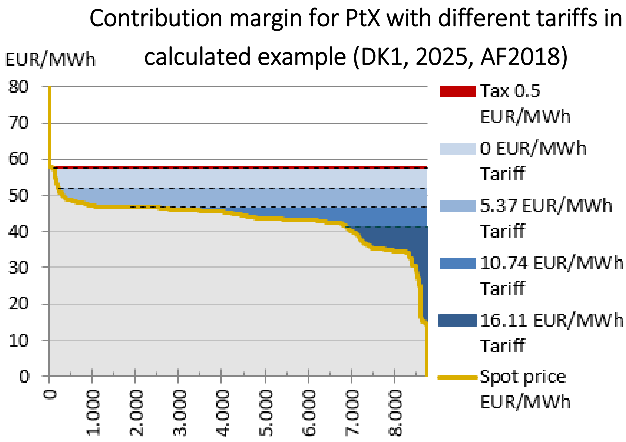
slightly better internal rate of return is seen with the 25 per cent lower CAPEX for solar cells in 2025, than if the whole RE facility consisted of onshore wind turbines with prices in line with the technology catalogue.

18 It is not sustainable if PtX is driven by electricity generation from fossil fuels, in order to subsequently simply produce a fuel, which would thus be fossil-based. However, during a transition phase from 'fossil fuel electricity generation' to renewable electricity generation, there may be good arguments for allowing electricity generated using fossil fuels into the consumption mix for PtX, since PtX facilitates better integration of fluctuating, renewable electricity generation from wind and solar power.

4.4 The tariff level is of great significance to the operating pattern and profitability of PtX.

As Figure 4.1 shows, tariffs constitute a major portion of the final electricity price. However, Figure 4.1 only shows the annual average. The calculation examples use individual hourly prices in DK1 in 2025. By looking at the total electricity price for each hour, one can see the impacts of the spot price, electricity tax and tariff on how much the electrolysis plant operates during a year, and how much is earned each hour (the contribution margin). Four variations on the tariff level have been used in the calculation example: 0; 5.37; 10.74 and 16.1 EUR/MWh. 10.74 EUR/MWh corresponds approximately to the transmission tariff. 16.1 EUR/MWh can illustrate the total tariff (transmission and distribution) for plant connected to the distribution network (at 10 kV or above). 5.37 EUR/MWh serves as an example of a reduced tariff, and 0 EUR/MWh (no tariff) has been included for reference.

Figure 4.2 illustrates earnings from PtX in the calculation example at various tariff levels with an offsite connection model, where all the power for the electrolysis is drawn from the public grid. The figure is based on the yellow line. This plots a 'duration curve', in which the 'raw' electricity spot prices for each of the year's 8,760 hours have been sorted from highest to lowest. The top edge of the red line is the ceiling price in relation to the final electricity price, which is also shown in Figure 4.1. The ceiling price is the electricity price at which the electrolysis is switched off, because the selling price for the methanol can no longer cover the final cost of the electricity at the given price or higher. To show the ceiling price in relation to the 'raw' electricity spot price, the electricity tax and tariff must be deducted from ceiling price at the final electricity price. This is shown in the figure via dotted black lines at the upper edge of the blue 'tariff areas'. The top dotted black line just below the red line is thus the ceiling price in relation to the spot price when the tariff is 0 EUR/MWh. The second dotted black line between the lightest and second-lightest blue areas is the ceiling price when the tariff is 5.37 EUR/MWh, and so on. The distance from the ceiling price down to the electricity spot price corresponds to the earnings for the given hour. The blue areas under a given tariff's ceiling price thereby indicate the earnings over the entire year, or the contribution margin for PtX in the calculation example. The areas must be 'accumulated' when reading the figure, such that the earnings at a tariff level of 10.74 EUR/MWh include both the second-darkest blue area (10.74 EUR/MWh) and the darkest blue area (16.1 EUR/MWh).



Figur 3.2

	Tariff	16.11 EUR/MWh	10,74 EUR/MWh	5,37 EUR/MWh	0 EUR/MWh
Size of each of the "blue areas"	EUR/kW	15	20	44	46
"Blue areas" accumulated	EUR/kW	15	35	80	126
Converted to 20 MW electrolysis. This corresponds to the gross margin in the case example.	Mio. EUR	0.3	0.7	1.6	2.5

The table under Figure 4.2 shows the size of each blue area. When these are accumulated (the second row in the table), they show the earnings/contribution margin in EUR per MWh of electrolysis. In the bottom line of the table, the contribution margin has been multiplied by the 20 MW capacity of the electrolysis plant. The figure and table clearly show that there are major differences in the size of the contribution margin at the various tariff levels. At a tariff of 16.1 EUR/MWh, the electrolysis operates for only just under 2,000 hours, and despite some hours with relatively high earnings due to very low electricity prices, the total area (contribution margin) is much less than at a tariff of 5.37 EUR/MWh, at which the electrolysis operates for more than 8,000 hours of the year.

Figure 4.2 shows not only the impact of the tariff, but also the major impact of the electricity spot price on earnings from PtX. If electricity prices are generally lower, the contribution margin (blue areas) will also be larger. But a duration curve with greater slope (e.g. if electricity prices are expected to vary more), will also typically increase the contribution margin for PtX (larger blue areas in Figure 4.2).

Figure 4.3 illustrates the impact of the shape of the duration curve (how variable the electricity price is throughout the year). The electricity price profile shown in Figure 4.3, results from using the method the Danish Energy Agency recommends for macroeconomic analyses of demand-side response in 'Macroeconomic calculation assumptions 2018' (*Samfundsøkonomiske beregningsforudsætninger 2018*). The new method for analysing demand-side response involves taking the average electricity price profile for a historical period, and 'normalising' it to the average price the electricity market models predict for a future year. The reason for using this new method for analysing demand-side response is that the electricity market models that both Energinet and the Danish Energy Agency use have difficulty capturing the variations in electricity price that arise due to factors like fluctuations in fuel and carbon prices in a given year. This is not so important when analysing mean prices, and price differences between price areas subject to the same fluctuations in fuel prices. But it is a significant challenge when investigating the value of demand-side response and sector coupling.

Applying the new method results in a quite different duration curve in Figure 4.3, even though the mean price is the same as in Figure 4.2. The total contribution margin for PtX without any tariff (the sum of all the blue areas) has risen from 2.5 million EUR to 2.8 million EUR, when multiplied by the calculation example's 20 MW electrolysis capacity. This is an increase of approx. 12 per cent. At higher tariffs, the contribution margin rises considerably. At a tariff of 16.1 EUR/MWh, the contribution margin has almost tripled, from 0.3 million EUR to 0.8 million EUR. At a tariff of 10.74 EUR/MWh, the contribution margin has almost doubled, from 0.7 million EUR to 1.3 million EUR.

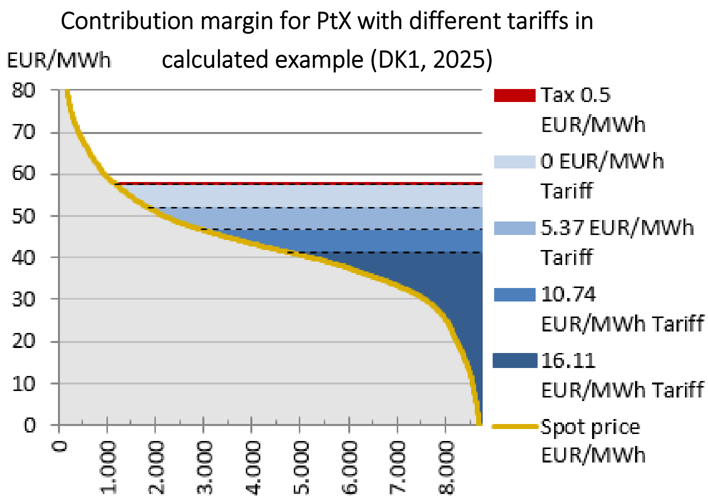


Figure 4.3

	Tariff	16.11 EUR/MWh	10,74 EUR/MWh	5,37 EUR/MWh	0 EUR/MWh
Size of each of the "blue areas"	EUR/kW	41	27	35	39
"Blue areas" accumulated	EUR/kW	41	67	102	141
Converted to 20 MW electrolysis. This corresponds to the gross margin in the case example.	Mio. EUR	0.8	1.3	2.0	2.8

The electricity market models, up to at least 2030 in any case, produce duration curves that are 'flatter', with less price variation at the centre, than those we have observed in recent years. The method from the macroeconomic assumptions 'copies' the price variation we have seen historically. It seems reasonable to assume that the price variations in the coming years will at least be similar to those we see today and are not likely to be significantly less. As Figure 4.3 shows, greater price variation would, all else being equal, result in greater value from demand-side response, including PtX.

However, the new method is not without problems. For example, it does not consider the increasing proportion of wind and solar power in the system, which can be expected to cause longer periods with very low prices – and the risk of periods with very high prices. Even though the new method clearly produces greater price variations towards 2030 than the electricity market models, it may still underestimate the component of the price variations that is due to a higher proportion of wind and solar power. Conversely, the method makes no allowance for any new infrastructure or flexible initiatives that might contribute to smoothing out the duration curve in future.

A perspective could be that the new method is poor from a technical perspective, as it simply projects history into the future. However, the Danish Energy Agency has recommended this method for analysing demand-side response. This is presumably because they believe history serves as a better guide to future electricity price variations than the electricity market models.

The traditional method (as represented in Figure 4.2) has been used in the rest of the example calculations in this chapter, with the knowledge that it probably underestimates the value of demand-side response from PtX.

4.4.1 Offsite PtX – profitability calculation example

Figure 4.2 in the previous section illustrates how the tariff and electricity spot price have a significant impact on the profitability of PtX. However, Figure 4.2 only shows earnings at various tariff levels before fixed costs (operation and maintenance and depreciation/repayment of CAPEX).

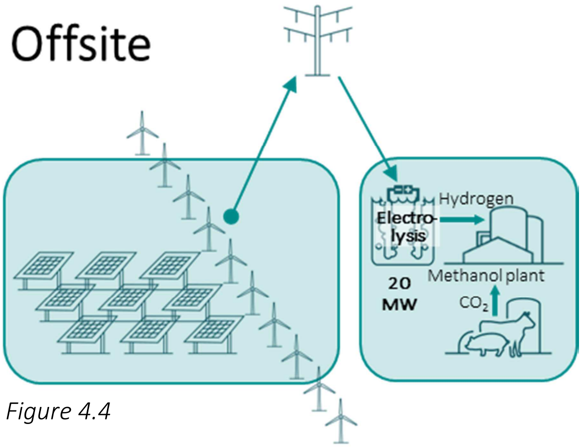
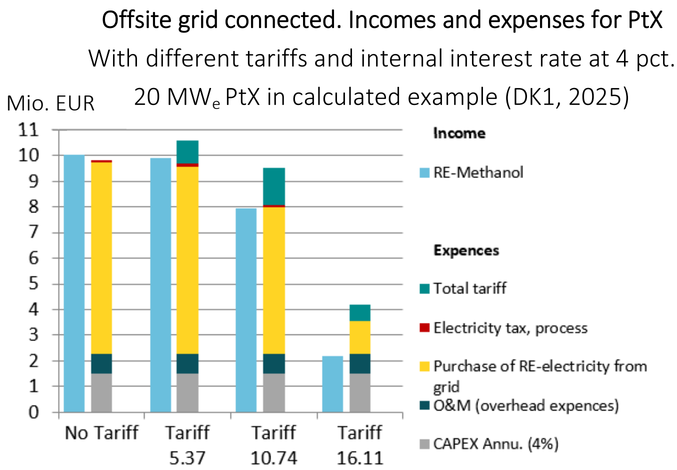


Figure 4.4

Figure 4.5, on the right, shows the total income and cost elements at different tariff levels for PtX in the calculation example (20 MWel), using an offsite connection model, as illustrated in Figure 4.4. The calculation here focuses on PtX component – no investment in wind and solar power. The CAPEX will be repaid at a fixed annual rate (annuity), with an interest rate of 4 per cent, corresponding to the macroeconomic real rate of interest. The table for Figure 4.5 also shows the internal rate of return, indicating the (real) rate of return on the investment at which, income and costs are in balance.[19] The internal rate of return will thus be exactly 4 per cent if the income and costs in the figure are equal. The internal rate of return can be used to assess whether a project will be of interest to investors. A private investor will typically require a significantly higher return than the macroeconomic rate of 4 per cent – especially for projects involving new technology and significant risks.



No Tariff	Tariff 5.37	Tariff 10.74	Tariff 16.11	*Amount in mio. EUR (2018 prices)*
10,1	9,9	7,9	2,2	RE-Methanol (income)
7,4	7,3	5,7	1,3	Purchase of RE-electricity from grid
0,0	0,9	1,5	0,6	Total tariff
0,1	0,1	0,1	0,0	Electricity tariff, process
2,5	**1,6**	**0,7**	**0,3**	**Contribution margin (cf. fig. 4.2)**
0,8	0,8	0,8	0,8	O&M (overhead expences)
1,7	**0,8**	**-0,1**	**-0,5**	**EBITDA**
5,4%	***-1,1%***	-	-	***Internal Interest, real***
1,5	1,5	1,5	1,5	CAPEX back, annuity (4%)
0,2	**-0,7**	**-1,6**	**-2,0**	**Profit after 4% real rate of interest**

Figure 4.5

With no tariff, the income for RE methanol in Figure 4.5 is slightly higher than total costs. It can also be seen that cost of electricity accounts for the vast majority of costs in this scenario, with electrolysis/methanol production running almost constantly. A tariff of 5.37 EUR/MWh results in a loss of 0.7 million EUR at an interest rate of 4 per cent. The internal rate of return is negative in this case, which means that not even the investment will be

19 The return in these calculation examples has simplistically only been calculated for year 1 of the project (2025 in this case). The internal rate of return has been calculated based on the assumption that EBITDA (at fixed prices) for each year of the project's lifetime equals EBITDA in year 1.

repaid during the lifetime of the project. At a tariff of 10.74 EUR/MWh, the electrolysis runs slightly less often (the height of the light blue bar), while the loss now stands at 1.6 million EUR – larger than the fixed CAPEX repayment. At a tariff of 16.1 EUR/MWh, the electrolysis only runs for a small portion of the annual hours (see Figure 4.2), and the loss of 2 million EUR is almost equal to the total fixed costs. Despite higher unit tariff of 16.1 EUR/MWh, total tariff costs are significantly less than at a unit tariff of 5.37 EUR/MWh, because the electrolysis is running for so few hours, and much less electricity is used.

For an offsite connection model, profitability in the calculation example is very sensitive to the tariff level. Together with the expected electricity price in 2025, thus the variations in the tariff determine whether the PtX plant returns an annual profit that is reasonably balanced with the macroeconomic return expectation (4 per cent), or a large loss. It is important to note that variations in the assumed electricity price have as much impact on profitability as the variations in the tariff. The assumed market price for the final product also has a major impact. The idea behind the calculation example is not to argue that PtX should be exempted from the tariff. Connecting production and consumption, and having the opportunity to buy exactly the quantity of electricity you need from the grid has a significant value – and cost. Rather, the point is that with very flexible/price-sensitive electricity consumption such as PtX, it is particularly important to have a tariff that represents true costs – from a macroeconomic perspective, as this impacts the operating pattern.

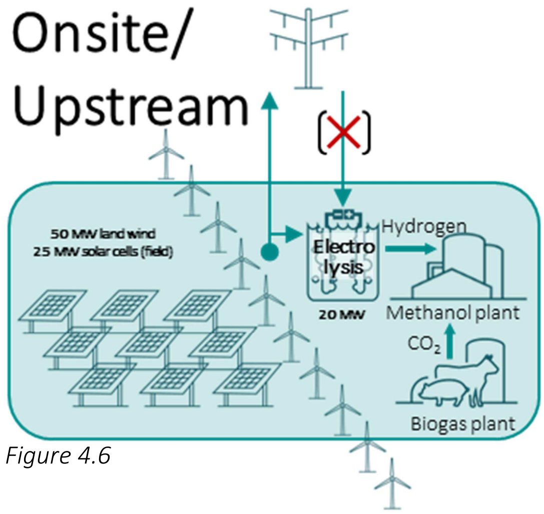


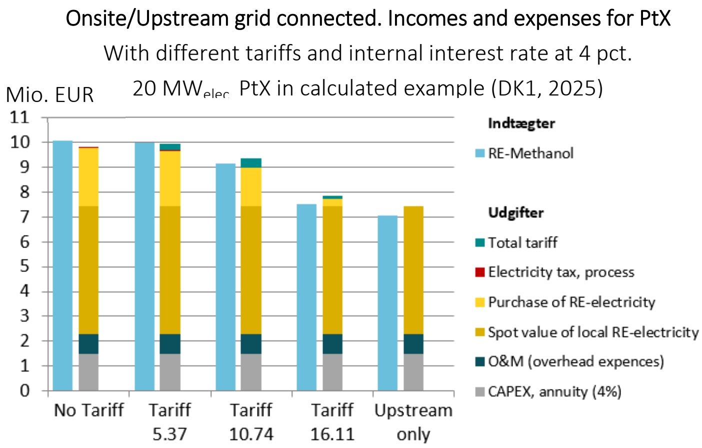
Figure 4.6

4.4.2 Onsite/upstream PtX – profitability calculation example

The previous section showed that the profitability for PtX using an offsite calculation model is very sensitive to the tariff level.

As explained in Chapter 3 on connection models, many players are therefore considering whether it is possible to supply a large portion of the electricity consumption for electrolysis directly from local renewable electricity generation. In addition to the potential for tariff savings, this also contributes to documentation that the final product has been produced using only renewable electricity.

Figure 4.6 shows the specific onsite/upstream setup in the calculation example, with local generation from 50 MW onshore wind power and 25 MW large scale solar cells, which can be used to supply the 20 MW electrolysis. With the onsite connection model, electricity can also be purchased from the grid when



No Tariff	Tariff 5.37	Tariff 10.74	Tariff 16.11	Upstream only	*Amount in mio. EUR (2018 prices)*
10,1	10,0	9,1	7,5	7,1	RE-Methanol (income)
2,3	2,2	1,5	0,3	0,0	Purchase of RE-electricity from grid
5,2	5,2	5,2	5,2	5,2	Spotvalue of local RE-electricity
0,0	0,3	0,4	0,1	0,0	Total tariff
0,0	0,0	0,0	0,0	0,0	Electricity tax, process
2,6	**2,3**	**2,0**	**2,0**	**1,9**	**Contribution margin**
0,8	0,8	0,8	0,8	0,8	O&M (overhead expences)
1,8	**1,5**	**1,3**	**1,2**	**1,1**	**EBITDA**
5,8%	***4,1%***	***2,5%***	***1,8%***	***1,5%***	***Internal interest real***
1,5	1,5	1,5	1,5	1,5	CAPEX back, annuity (4%)
0,3	**0,0**	**-0,2**	**-0,3**	**-0,4**	**Profit after 4% real rate of interest**

Figure 4.7

there is not enough local renewable electricity generation. With the upstream connection model, no electricity is purchased from the grid, in order to have very simple and compelling documentation that all electricity consumption for the electrolysis comes from renewable electricity generation.

The columns in Figure 4.7 and the accompanying table show that the tariff level has much less impact for an onsite connection model. As for the offsite connection example in the previous section, only the PtX component has been modelled, but onsite connection allows a large portion of the electricity consumption to be purchased with no tariff from the local renewable electricity generation (the dark yellow part of the cost column). At a tariff of 5.37 EUR/MWh, income and costs still balance for an onsite connection model (internal rate of return of 4 per cent). But the biggest difference from the offsite calculation is that profitability of the onsite model is much less sensitive to the tariff level, as a large portion of electricity consumption comes from tariff-free local production.

These profitability calculations cannot be used to make a business case for a specific project. Too many project-specific cost and income items are missing. But the example calculations show that it may be possible to develop some PtX projects, even in the short term, that are at least macroeconomically viable (4 per cent real rate of return), even though this rate of return is somewhat low in relation to private investment in a new and unknown technology. The above calculations also show – particularly when all power for electrolysis has to be purchased from the grid – that the profitability of PtX in the calculation examples is very sensitive to the tariff level. The sensitivity illustrated is not tied directly to the tariff level, but to the final electricity price for the electrolysis, of which the tariff is an important element.

4.5 Electricity price sensitivities – and potential to hedge wind and solar power using PtX

While the tariff may make up a substantial part of the final electricity price, the electricity spot price still accounts for the largest proportion of the costs of PtX. Therefore, sensitivities have been calculated on the 'raw' electricity price. The calculation and results include investment in renewable electricity generating facilities, comprising 50 MW onshore wind and 25 MW large scale solar cells in 2025. The total 75 MW of renewable electricity generation capacity is 3.5 times the 20 MW electrolysis capacity of the PtX plant. The total investment (CAPEX) in wind/solar in the calculation example is almost 61,74 million EUR. The total investment in the PtX plant is about 23.45 million EUR, or about 40 per cent of the investment in the RE facility.

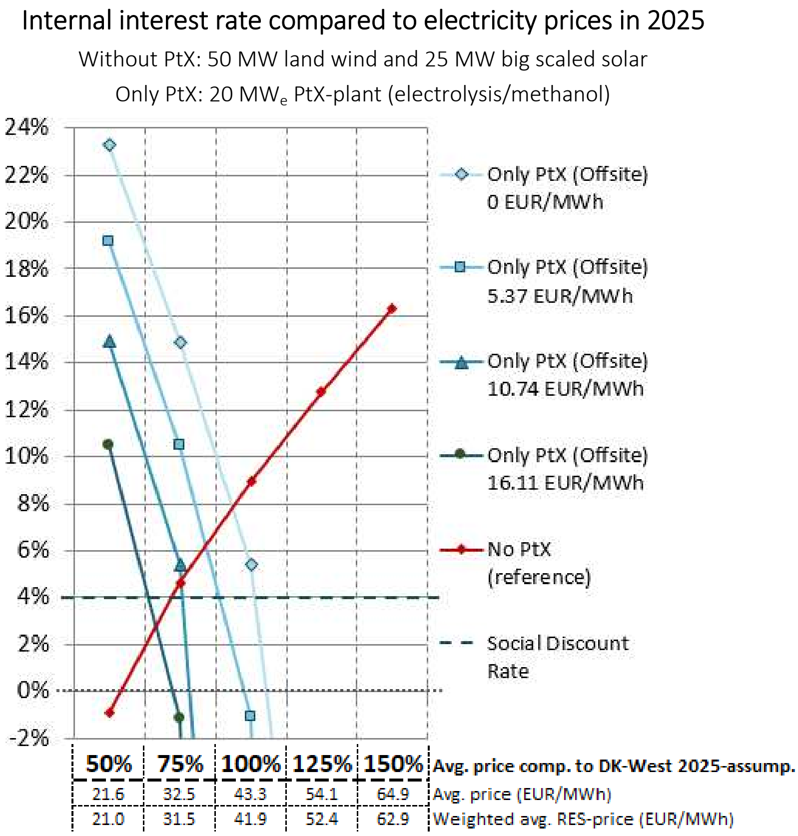


Figure 4.8

The profitability of wind and solar power generation, all else being equal, rises with the electricity price, while the profitability of the electricity consuming PtX falls. The strong and opposite effect of the electricity price on profitability is clearly seen in Figure 4.8, where the assumed electricity price in 2025 (100%) is varied by +/-25 per cent and +/-50 per cent, which is not unlikely from a historical perspective. For example, the average electricity spot price rose by approx. 50 per cent from around 27 EUR/MWh at the beginning of 2018 to around 40 EUR/MWh at the beginning of 2019.

The red line shows profitability of the wind/solar plant alone. At the assumed electricity price (100%), corresponding to an average settlement price of 41.88 EUR/MWh, the internal rate of return is about 9 per cent (real). This is without any government RE subsidy. This rate of return would appear to be of commercial interest for a mature technology with limited technical risks. But at an electricity price just 25 per cent lower (75%), the internal rate of return is 'only' hovering around the macroeconomic 4 per cent level. At an electricity price 50 per cent lower than assumed in 2025, there is actually a negative return on the RE facility. Conversely, the internal rate of return quickly rises to attractive double-digit percentages if the settlement price is higher than expected in 2025.

The blue lines on Figure 4.8 show the internal rate of return for the PtX plant alone at various tariff levels. As was shown in section 4.1.1, PtX in an offsite connection model has difficult conditions at the assumed electricity price for 2025 in the calculation example. Without any tariff, the internal rate of return scrapes in at 5.4%, but is already negative at a tariff level of just 4.37 EUR/MWh. But at lower electricity prices, the model suddenly looks much better. At 25 per cent lower electricity prices (75%), the internal rate of return rises above 10 per cent with a tariff of 5.37 EUR/MWh, and is even above the macroeconomic 4 per cent level with a tariff of 10.74 EUR/MWh. At 50 per cent lower electricity prices, the PtX plants business case varies between being good and great business, depending on the tariff level.
The many wind and solar power projects that are taking over an increasing share of electricity generation – due to reduction in the price of the technology, have a significant and narrow financial risk profile due to their high sensitivity to the electricity price. This increases the risk premium in these project's rate of return requirements. One could say, what is needed is a large volume of flexible/interruptible electricity consumption that can match the ever-increasing volume of inflexible electricity generation from wind and solar power. PtX has potential to deliver this flexibility in large volume. By combining wind/solar projects with PtX, investors can hedge against the sensitivity of these projects to low electricity prices.

When the RE facility in the calculation example with 50 MW wind and 25 MW solar power is combined with a PtX plant with 20 MW of electrolysis, the electricity price sensitivity looks completely different. The additional investment in PtX of about 40 per cent of the CAPEX for the wind/solar plant offers implicit hedging for the electricity price. If the electricity price is low the PtX plant is profitable, and if the electricity price in high the wind/solar plant is profitable. The red line in Figure 4.9 is the same as in Figure 4.8 and shows the internal rate of return for the RE facility alone, with great sensitivity to the electricity price. The green, yellow and blue lines show the internal rate of return for the combined RE/PtX project, for various connection models and tariffs.

The combination of RE and PtX generally offers significant hedging against the electricity price, with a far more stable return irrespective of the price. While the internal rate of return may not be remarkable for a private

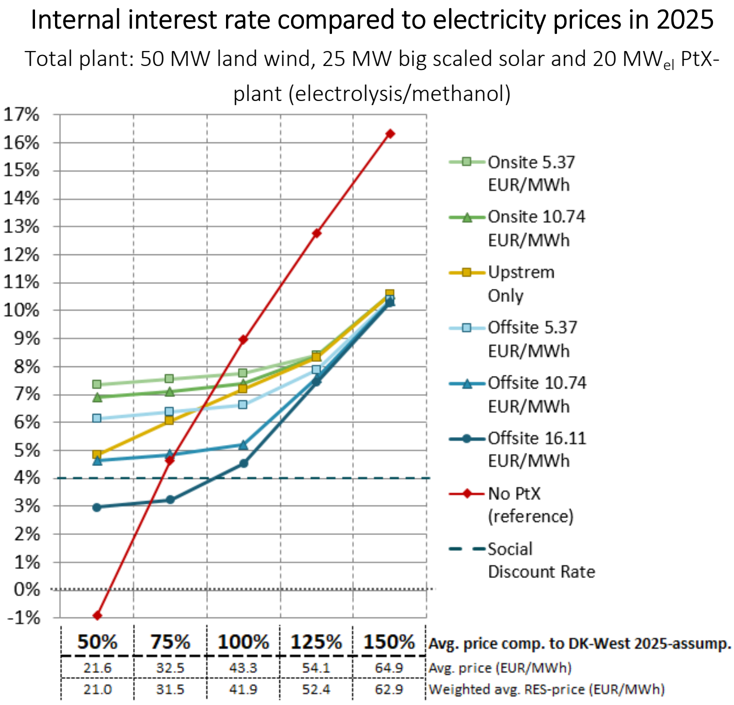


Figure 4.9

investor, it is at least positive for all selected sensitivities. Except for the offsite connection model with a tariff of 16.1 EUR/MWh, the internal rate of return is above the macroeconomic 4 per cent level, irrespective of the electricity price.

It should be noted that the sensitivity calculation for the electricity price in 2025 is quite simple. For example, the 50 per cent sensitivity model was created simply by reducing the electricity price by 50 per cent for all hours in the assumed electricity price scenario for 2025. A different electricity price profile with greater variation in electricity prices for individual hours, either due to greater price pressure from wind and solar power or greater variation in the 'normal price range', as shown in Figure 4.3, would increase return on flexible electricity consumption such as PtX, even with the same average price.

For the example calculations illustrated in figure 4.8 and 4.9 it is important to notice that results cannot be used for a specific case calculation. However, figures show that there is likely to be a significant potential for hedging investments in wind and solar power using PtX. Hedging that could help to significantly reduce the electricity price risk associated with separate investments in wind and solar power. All else being equal, such hedging should lead to a lower return on capital requirement for such investments. Given that there are still very few large scale PtX plants, there continue to be many risks associated with being a first mover in this area, and these will probably increase the return on investment requirements of private investors. However, the hedging potential PtX offers means it is not inconceivable that large investors in renewable electricity generation from wind and solar power might be interested in contributing to the maturation, implementation and upscaling of PtX technology. The example calculations also suggest that even in the short term, PtX will be able to contribute to increasing flexible/interruptible electricity consumption, and hence also to macroeconomic resilience towards low electricity prices. PtX is considered a key technology for the transition away from fossil fuels. This analysis suggests that PtX may potentially be economically relevant even in the short term. It may therefore be relevant and timely to ensure the regulatory framework now, so uncertainties in relation to this new technology in the energy system, do not end up being barriers to investment in PtX projects in the short term.

5. Case examples of initiatives and specific PtX projects

The following examples of PtX projects and initiatives are by no means exhaustive. We have chosen some regional/national cases examples which could materially affect development and market maturation of PtX in the short term and/or have significant Danish and commercial characteristics.

5.1 Case 1: Oil giants entering the PtX market

Large amounts of hydrogen are currently used to refine crude oil into fuels such as petrol and diesel. Processes for desulphurising fuels, in particular, require large amounts of hydrogen. More stringent environment legislation covering emissions, such as the 'SOx Emission Control Areas'[20], are likely to increase the need for hydrogen in refining industry in the future.

Given that the vast majority of the hydrogen currently used in refineries is extracted from fossil fuels[21], several oil producers and refiners have begun investigating the possibility of producing and using hydrogen produced by electrolysis powered by renewable electricity generation.

Examples of value streams resulting from using RE electrolysis hydrogen at oil refineries:

- Reduce the CO_2 intensity of their fuel production, both for processing and product upgrading.
- Supply RE hydrogen as a transport fuel (fuel cell vehicles).
- Internal 'load balancing' of the product flows at the refinery.
- Sell services for balancing the electricity system.
- Supply residual heat for district heating.

Using the above value flows as arguments, Shell announced in 2017 that they would build the world's largest PEM electrolysis plant for production of hydrogen at the Rhineland refinery in Germany. The electrolysis capacity will be 10 MW_{el}, producing approx. 1,300 tonnes of hydrogen per year. The refinery – one of the largest in Europe – already has an annual hydrogen consumption of 180,000 tonnes. The electrolysis plant is expected to commence operation in 2020.

A similar project involving at least 10 MW electrolysis is on the drawing board for Shell's refinery in Fredericia, Denmark, but is awaiting a decision on possible subsidisation as a demonstration project.

The refinery industry in Europe has the potential to become an important player in relation to large-scale electrolysis. Particularly if RE-based hydrogen for process purposes (e.g. desulphurisation) is permitted to be included in the RE component requirement for fuel producers from 2021 under the revised RE directive. Several market participants see the refinery industry as a key player in relation to upscaling electrolysis plants, due to their purchasing power and high demand, and the fact that a conversion phase can be saved, as the RE hydrogen is used directly, typically replacing hydrogen derived from natural gas.

5.2 Case 2: Green ammonia for shipping

In April 2018, the International Maritime Organisation (IMO) negotiated a global agreement to reduce CO_2 emissions from international shipping by at least 50 per cent by 2050, compared to 2008. Maersk, the world's largest container

20 Areas with stricter SOx emission limit values for shipping.

21 Approx. 75 per cent comes from steam reforming of natural gas or other hydrocarbons, while the rest is recovered from hydrogenous flows generated in the refinery process itself.

shipping company, announced in a press release and in the Financial Times in December 2018 that they will be CO_2 neutral by 2050:

> As world trade and thereby shipping volumes will continue to grow, efficiency improvements on the current fossil based technology can only keep shipping emissions at current levels but not reduce them significantly or eliminate them.
> "The only possible way to achieve the so-much-needed decarbonisation in our industry is by fully transforming to new carbon neutral fuels and supply chains," says Søren Toft, Chief Operating Officer at A.P. Moller – Maersk.
> ...
> "The next 5-10 years are going to be crucial. We will invest significant resources for innovation and fleet technology to improve the technical and financial profitability of decarbonised solutions." [22]
>
> *Extract of Maersk's press release from 4 December 2018*

One of the possible green bunker fuels for shipping currently receiving intense interest is electrolysis-based ammonia (NH_3). Ammonia has the chemical properties to allow it to function directly as fuel in a traditional marine engine, and as a replacement for traditional bunker fuel, it would eliminate the ship's CO_2, sulphur (SOx) and particulate emissions ($PM_{2.5}$).

MAN ES, whose ship engines provide propulsion for over half of the world's heavy cargo vessels, announced in January 2019 that they are refining their existing LPG (Liquefied Petroleum Gas) marine engine model to be able to operate using pure ammonia. Ammonia – like pure hydrogen – has the advantage over alternatives such as green methane, methanol and other RE fuels (hydrocarbons), that it is not dependent on a carbon source for production, and does not emit CO_2 during combustion. Compared to hydrogen, ammonia takes up far less space and is a liquid at low pressure. Ammonia is not flammable like hydrogen, but is toxic if spilled, and must therefore be handled professionally.

MAN ES has teamed up with a number of international players, including Siemens Gamesa Renewable Energy and three shipping companies, who has yet to be announced, in a consortium, which aims to develop electrolysis-based green ammonia for shipping.[23]

If international shipping seriously begins to make use of PtX fuels, this will have a major impact on the diffusion of PtX technology and demand for further renewable electricity generation. For example: If all the electricity produced at the large Danish Horns Rev 3 offshore wind farm (407 MW), brought online in early 2019, was converted into a PtX fuel such as green ammonia, it would only provide enough fuel to keep about two of Maersk's large, energy-efficient (Triple-E) container ships operating.

5.3 Case 3: Sector coupling between the electricity and gas infrastructure

Interest in PtX technology in Europe among infrastructure operators has been mainly limited to the gas sector in the past. However, this has changed over the past year, as electricity TSOs (Transmission System Operators) have begun to show interest in the advantages of connecting electricity and gas infrastructure. This was evident, for example, in

22 https://www.maersk.com/news/2018/12/04/maersk-sets-net-zero-co2-emission-target-by-2050
See also: https://www.bloomberg.com/news/articles/2019-03-21/maersk-tests-biofuel-as-it-sets-sail-for-2050-carbon-neutrality

23 https://www.mpropulsion.com/news/view,man-energy-solutions-to-launch-twostroke-ammonia-fuelled-engine_56641.htm
https://www.ammoniaenergy.org/man-energy-solutions-an-ammonia-engine-for-the-maritime-sector/
https://www.tradewindsnews.com/gas/1679172/ammonia-swings-into-frame-as-a-potential-future-marine-fuel

publication in October of a joint position paper by the European TSO associations for electricity and gas – ENTSO-E (electricity) and ENTSOG (gas): "Power to Gas – A Sector Coupling Perspective"[24]. The position paper highlights the positive characteristics that PtG/PtX can potentially contribute to the operation of both the electricity and gas grids. Coinciding with the launch of the joint position paper, an agreement was entered into to work closely together on developing a common electricity and gas model, which better reflects interdependence of the two sectors and the added value coupling can potentially create. Examples of this type of collaboration on joint value creation between electricity and gas infrastructure include: 'North Sea Wind Power Hub'[25] and the two German 100 MW PtG/PtX projects: 'Hybridge'[26] and 'Element One'[27]. Projects where electricity and gas TSOs have entered into collaboration on large-scale PtG/PtX.

Another interesting example is a new joint study from the Gasunie gas TSO and Tennet electricity TSO.[28] They have jointly analysed potential development paths for electricity and gas infrastructure in the Netherlands and Germany up until 2050. The scenarios show that in future energy system, electricity, heating and gas will be increasingly integrated to absorb the large fluctuations in solar and wind power generation. The analysis thus shows that not only the electricity infrastructure, but also the existing gas infrastructure, will play a key role in the future energy systems. The general conclusion regarding value creation for electricity and gas infrastructures behind the analysis is that the future need for investments in infrastructure can be reduced through sensible planning of networks and location of electrolysis plants, and using both gas and electricity.

One driver for the integration of electricity and gas infrastructure via PtX in future could be the Connecting Europe Facility (CEF), which aims to promote and support the development of trans-European networks in the areas of transport, energy and digital services. The reason for this is the current proposal for change would allow RE production facilities to receive support through the Project of Common Interest (PCI) pool, as well as the infrastructure that has to transport the energy.

5.4 Case 4: Ørsted aims to scale up and reduce the price of green hydrogen

Ørsted, the world's largest developer of offshore wind projects, announced in March 2019 that they would begin working on the conversion of offshore wind to green hydrogen via electrolysis.

> Green hydrogen
>
> As part of its bid on Netherlands Coast South 3 & 4, Ørsted is working to establish green hydrogen projects which will be connected to Ørsted's Dutch offshore wind farms.
>
> "The use of offshore wind power to produce green hydrogen through electrolysis can help other sectors, such as heavy industry and transport, to reduce their CO_2 emissions. The production and sale of green hydrogen for large industrial customers can ensure a more stable income from offshore wind farms that are dependent on the market price of electricity, as Holland Coast South 3 & 4 will be. We are ready to scale up and reduce the cost of green hydrogen, as we have done with offshore wind power," says Henrik Poulsen.[29]

24 https://www.entsoe.eu/2018/10/15/power-to-gas-a-sector-coupling-perspective/
25 https://northseawindpowerhub.eu/
26 https://ptg.amprion.net/
27 https://element-eins.eu/
28 https://www.tennet.eu/fileadmin/user_upload/Company/News/Dutch/2019/Infrastructure_Outlook_2050_appendices_190214.pdf
29 https://orsted.com/da/Media/Newsroom/News/2019/03/Orsted-participates-in-tender-for-Holland-Coast-South-3-4-offshore-wind-farm

Excerpt from Ørsted's press release of 14 March 2019

Ørsted highlights both the potential of electrolysis/PtX in relation to decarbonising heavy industry and transport, and the ability of hydrogen production to hedge the value of electricity generation from wind turbines, as described in section 4.5. It is noteworthy that the world's largest offshore wind player has announced that they are ready to scale up and reduce the cost of green hydrogen. If electrolysis/PtX in Europe is to ever reach a scale that can displace fossil fuels such as gas and oil, it will presumably require a major expansion in cheap, large scale offshore wind.

5.5 Case 5: H2BusEurope to launch 200 hydrogen busses in Denmark

NEL announced in September 2018 that their large-scale hydrogen bus project, H2BusEurope, had received EUR 40 million from the European CEF programme[30] to roll-out 600 hydrogen fuel cell buses in selected areas of Europe. The project aims to bring 200 hydrogen buses to the roads in each of these three countries: the UK, Latvia and Denmark. NEL, based in Norway, is one of the world's largest manufacturers of electrolysis plants, and owns Nel Hydrogen Solutions (formerly H2 Logic) in Herning, Denmark, which develops and produces hydrogen filling stations.

Hydrogen for road transport in fuel cell vehicles is still a technology in its infancy. With 10 hydrogen filling stations, Denmark is currently the country with the best hydrogen refuelling infrastructure coverage in the world. However, there are still less than 100 registered hydrogen fuel cell vehicles in Denmark. The large-scale deployment of 200 hydrogen buses in Denmark can therefore be expected to have a major impact on maturing and reducing the price of this emission-free transport technology.

Fuel cell vehicles are essentially electric vehicles, in which the fuel cell and fuel acts as a range extender for a battery. Fuel cells are thus an attempt solve the challenge of providing an emission-free technology for heavy vehicles, for which the weight of batteries can become a limiting factor.

According to the news item on the website of the Danish Ministry of Energy, Utilities and Climate[31], the first hydrogen buses under the project are planned to hit the streets in 2020. It is reasonable to expect that the project aims to use green hydrogen produced through electrolysis powered by RE electricity, and that an attempt will be made to establish the necessary hydrogen production in Denmark. For 200 hydrogen buses, 10-20 MW of electrolysis will be required (depending on the number of full-load hours).

5.6 Case 6: Green Hydrogen Hub (GHH) – large scale production of RE hydrogen in Denmark

Green Hydrogen Hub is a consortium made up of Danish and international players. Consortium members include Gas Storage Denmark, Nouryon (formerly AkzoNobel Specialty Chemicals) and Hydrogen Valley.

The consortium is in the process of analysing the potential for a 150+ MW electrolysis plant. This will use green Danish electricity to produce RE hydrogen, and have integrated underground storage in an existing or new salt cavern in Jutland. The green hydrogen is expected to be sold to third parties, who will presumably use most of it in the production of green fuels for the transport sector, such as methanol or ammonia. The green hydrogen can also be used in the chemical industry and at refineries.

The consortium sees the greatest barriers to the realisation of the project as being regulatory. There is a need for a tariff product that takes into account the flexible and fully interruptible electricity consumption of the electrolysis, in

30 CEF (Connecting Europe Facility) aims to promote and support the development of trans-European networks in the areas of transport, energy and digital services.

31 https://efkm.dk/aktuelt/nyheder/2018/sep/danmark-har-faaet-en-stor-pose-penge-til-brintbusser/

relation to the electricity infrastructure, and for a model for how green electricity can be used to produce certified green hydrogen, even when the electricity is drawn from the public grid. The time horizon for the commissioning of the large scale PtX plant is expected to be around 2025.

5.7 Case 7: GreenLab Skive business park

GreenLab Skive is in the process of being built as a full scale 60-hectare business park, where companies can establish themselves and commercially develop and demonstrate the intelligent energy and resource solutions of the future. The business park is built around a symbiosis network, as infrastructure for a wide variety of energy flows: Local electricity generation from wind turbines and solar cells; infrastructure for hydrogen, oxygen, biogas, methane gas and landfill gas; a power grid with various voltage levels and heating pipes at various temperatures.

The business park is connected to the national transmission grids for electricity and gas. The idea is to utilise the surplus energy and resources in various forms from one company, as input to the energy processes and products of other companies. It is thus a commercially-driven business setting for the individual companies, which can each optimise the value of their energy and resource flows through the joint infrastructure of the business park and the local renewable electricity generation.

Key elements of the business park include:

- Locally produced electricity from an approx. 80 MW combined wind/solar facility (GreenLab Skive Wind Aps – project under approval)
- A large biogas plant with expected annual production of 19 million m^3 biogas (GreenLab Skive Biogas Aps – plant under construction)
- Approx. 5-20 MW electrolysis (being planned)
- Electrolysis and methanisation (being planned)
- A Plastic-to-Liquid plant – recycling waste plastic to produce liquid products for the petrochemical industry and fuel for transport (Quantafuel Skive ApS – expected to be operational in Q3 2019, with planned expansion in 2021)
- A plant for the production of PtX ammonia (a cooperation agreement has been entered into with Siemens Gamesa covering a pilot plant)
- The National Research Centre for Intelligent Energy and Energy Storage, in cooperation with DTU and AAU (several approved research projects are in progress)
- GreenLab Academy – an HV Centre offering continuing and further education programmes in the high voltage field (under planning).

More information about GreenLab Skive is available at: http://www.greenlabskive.dk/ or https://www.skive.dk/greenlab

COLOPHON

Energinet
Tonne Kjærsvej 65
DK-7000 Fredericia

+45 70 10 22 44
info@energinet.dk
CVR-nr. 28 98 06 71

Author: CVT/TYJ
Date: 2. April 2019
English translation v.1.00: 4. September 2019