ELECTRIFICATION OF INDUSTRY

FACILITATING THE INTEGRATION OF OFFSHORE WIND WITH POWER-TO-HEAT IN INDUSTRY

Akzo Nobel, Deltalinqs, Shell & TenneT

SAFER, SMARTER, GREENER

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CONTENTS

EXECUTIVE SUMMARY

Utilization of Power-to-Heat (P2H) technology is a method of decarbonizing industry that simultaneously can facilitate the integration of offshore wind in the power system.
In order to achieve the national goal of 49% reduction in CO_2 emissions by 2030, Dutch industry has been tasked with cutting its emissions by 14.3 Mt in addition to the current policy scenario. Based on the potential for P2H of about 5 GW (estimated to be achievable before 2030), emissions reductions of up to 4.5 Mt can be realised by combining the increased electrical demand with increased renewable production. This reduction is over 30% of the industrial target. In the future, these CO_2 savings can potentially increase up to 9 Mt.

In addition to direct reductions in CO_2 emission by reducing the demand for natural gas, P2H can have further benefits for the electricity supply system in the Netherlands due to synergies in both capacity and geography with the feed-in of offshore wind. The important heat demanding (chemical) clusters are located close to the locations where offshore wind will come ashore (see figure 1). Governmental plans currently account for the rollout of 11 GW in offshore wind in the North Sea, but initiatives are being developed to increase this to 17 GW or even 30 GW up to 2030 and 76 GW in the longer term. The transport grid is currently expected to be able to facilitate up to 6 GW in coastal locations, and up to 10 GW when utilizing connections further in-land, after which the grid can become constrained. This will lead to significant additional investment costs, and the risk that transport grid expansion and reinforcement will not be able to keep up with the growth of offshore wind production capacity. Enabling P2H in industrial clusters along the coast could support the system and potentially lead to lower investment costs by reducing the strain on the transport grid through the creation of demand at the point of feed-in, although reinforcement of the local grid might be necessary to support the added load. Additionally, the added demand could reduce the price risk for investments in further offshore wind development, enabling a faster transition to a sustainable system.

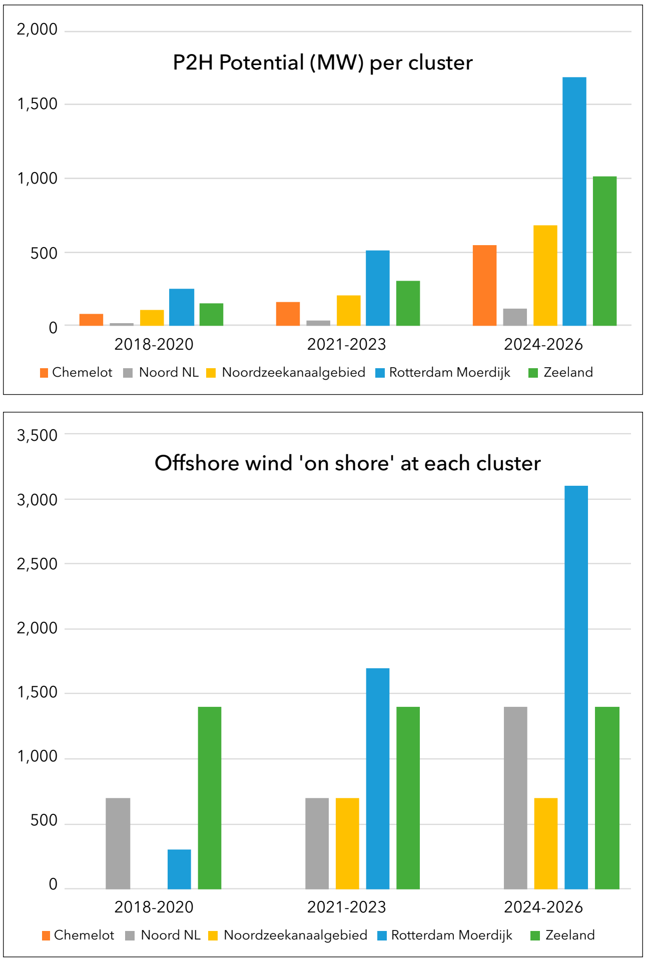


Figure 1 - Match between geographic P2H potential and offshore wind feed-in[1]

[1] Based on tenders announced. Increasing capacity growth in offshore wind from 1 GW to 2 GW per year is currently under discussion.

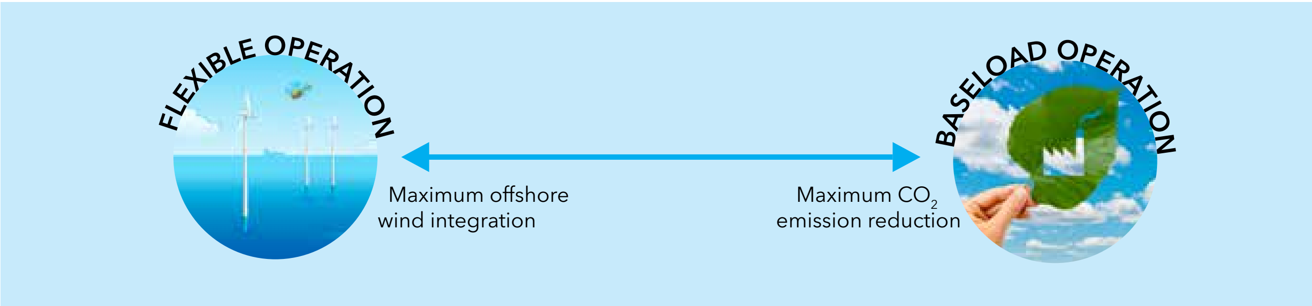


Figure 2 - Operating trade-off for hybrid boiler systems

To date, despite mature and readily available technology, only a marginal portion of the P2H potential has been realised. The main reasons for this are the investment barrier for electrical infrastructure to replace the gas infrastructure already in place, and the existent cost gap between P2H and the traditional gas-fired alternative. To fully unlock the potential, it is necessary to close the cost gap for P2H. Closing this cost gap can be done through regulatory change and/or direct financial incentives.

The operations of P2H facilities can be characterized between the two modes: baseload- or flexible use. The latter implies using hybrid systems that can switch between electricity and gas for the supply of heat. Flexible operation is most suited for facilitating offshore wind integration, as demand can be matched to supply. Baseload operation has the highest potential for CO_2 emission reduction, when supplied with renewable generation. A sensible transition path would be to start combining electric boilers with existing gas boilers, creating integrated hybrid systems. Once the original gas boilers are end-of-life, the electric boilers may continue to operate as baseload. In the future, these could be replaced for specific applications by more efficient high-temperature heat pumps, once technology has progressed sufficiently.

It is possible to optimize operation of hybrid boilers based on:

- Economics, utilizing electricity only when prices are lower than gas prices, or
- Grid support, switching between electricity and gas in order to avoid congestion, or
- CO_2 reduction, maximizing the amount of electrically operated hours during offshore wind production

Based on current policy and expected market development, P2H is not expected to become economically viable, regardless of the operating regime. Therefore, additional instruments are necessary to close the cost gap between the hybrid boiler and the natural gas option.

Measures to reduce the cost gap for a hybrid boiler aimed at integrating offshore wind (or flexible operation) should be focused on transport tariff redesign and a subsidy on investment costs. For maximizing CO_2 reductions, a subsidy that closes the price gap between electricity and natural gas is most effective.
Increasing the number of operational hours will cause a shift in the contributing factors of the marginal costs per MWh in heat produced electrically. A low number of hours operated electrically means that the marginal cost will be dominated by grid tariffs and investment costs, a high number of hours will lead to marginal costs being dominated by commodity prices.

In this report, the optimal operating regime from a system perspective has been determined to be around 4,500 hours operated electrically per year.
This is equal to the average number of full-load hours of an offshore wind farm. With these parameters, matching the electrical demand from the P2H facilities to the production of additional offshore wind production - either contractual or through market-based incentives - could lead to 4.5 Mt in CO_2 emission reduction. When switching to baseload operation, fuelled by 100% renewables, this can increase to 9 Mt in CO_2 savings.

Based on the calculations in this report, the total costs for closing the cost gap will be 250 MEUR annually for a 12-year period, or around 60 EUR/ton CO_2 saved. In baseload operation, this might rise to 170 EUR/ton CO_2 saved. These costs can be divided across three dimensions: transport tariff redesign, investment costs in P2H equipment and grid infrastructure, and commodity prices.

There are multiple ways of implementing an instrument that closes this cost gap. However, this instrument should at least:

- Close the cost gap for P2H
- Facilitate a match of P2H demand and offshore wind production
- Solve the chicken-and-egg-problem between additional demand and additional production, and match growth of demand and production in time
- Fair allocation of CO_2 savings

As industrial turnarounds typically have up to six years in between, and require up to four years in advance to plan, implementation of any such instruments is necessary before 2020 to allow sufficient time for the industry to implement P2H systems. Given the national climate ambitions and the P2H technology perspective it is recommended to start setting up pilot projects as soon as possible to gain practical experience with the alignment of production and demand.

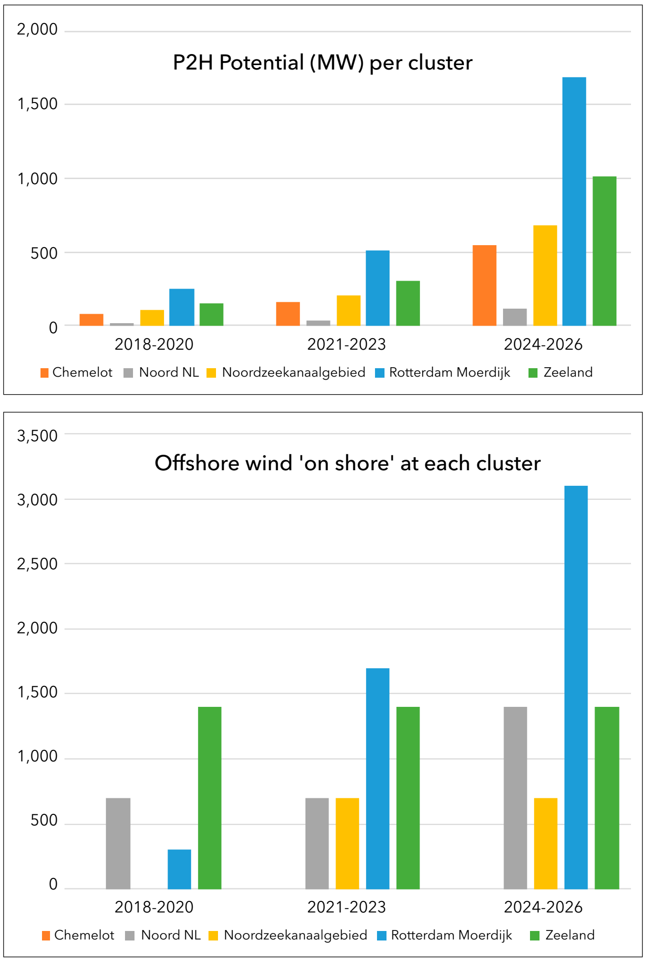
Once P2H can be fed using 100% renewables, baseload operation can push total CO_2 emission reduction to 9 Mton. This level of reduction can bring both industry and the Netherlands closer to achieving their respective climate goals, and take a big step toward a more sustainable society.

MANAGEMENT SAMENVATTING

Met de inzet van Power-to-Heat (P2H) technologie kan decarbonisatie in de industrie gerealiseerd worden, terwijl tegelijkertijd offshore wind beter in de energievoorziening ingepast kan worden.

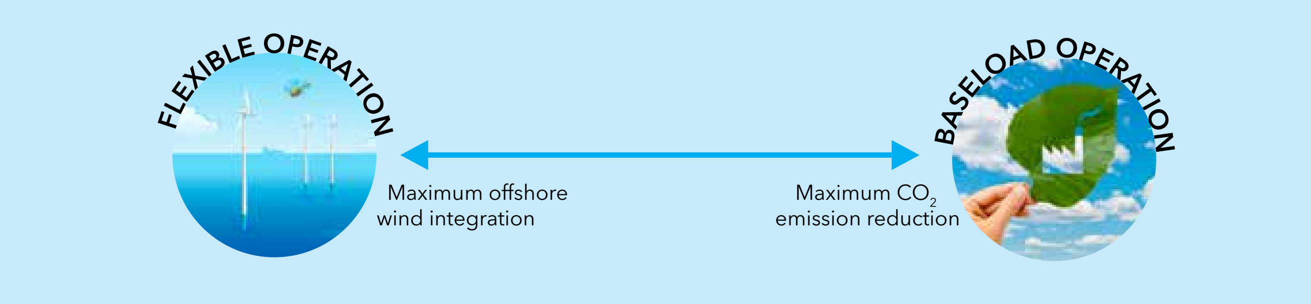
Om de nationale doelstelling van een 49% CO_2-emissie reductie in 2030 te kunnen realiseren, heeft de Nederlandse industrie de opdracht gekregen haar emissies met 14.3 ton terug te brengen, bovenop het reeds voorgenomen beleid. Op basis van een berekend P2H-potentieel van circa 5 GW (naar inschatting te realiseren voor 2030) kan een emissiereductie van 4,5 Mt behaald worden door deze toename in elektriciteitsvraag in te vullen met nieuw opgesteld duurzaam opwekvermogen. Deze reductie bedraagt meer dan 30% van de industrie opdracht. Op termijn kan de CO_2-besparing mogelijk verder toenemen tot 9 Mt.

Naast de directe CO_2-emissiereductie, ten gevolge van verminderd aardgasgebruik, biedt P2H de Nederlandse elektriciteitsvoorziening bijkomende voordelen door een synergie in vermogen en geografie met de inpassing van offshore wind-energie. De voornaamste clusters waar de industriële warmtevraag is geconcentreerd, bevinden zich op korte afstand van de locaties waar de offshore windenergie aan land komt (zie figuur 3). Het huidige overheidsbeleid gaat uit van een uitrol van 11 GW in offshore wind op de Noordzee tot 2030. Echter er worden plannen ontwikkeld voor een toename tot 17 GW of 30 GW naar 2030, en tot 76 GW op de langere termijn. Naar huidige inschatting kan het transportnet tot circa 6 GW faciliteren op kustlocaties, en tot 10 GW wanneer de verbindingen verder landinwaarts worden ingezet. Daarboven wordt het net overbelast. Deze beperking kan leiden tot aanzienzienlijke aanvullende investeringen, alsmede het risico dat de uitbreiding en verzwaring van het transportnet geen gelijke tred kan houden met de toename in het opgesteld offshore windvermogen. Toepassing van P2H in de industrie clusters langs de kust kan bijdragen aan een verlaging in benodigde investeringskosten door het reduceren van de belasting op het transportnet op plekken waar offshore wind wordt ingevoed. Het kan hiervoor echter wel nodig zijn om het lokale distributienet te verzwaren. Een verder bijkomend voordeel is dat de toegenomen vraag het investeringsrisico voor nieuwe offshore windparken kan beperken, wat een snellere transitie naar een duurzame energievoorziening mogelijk kan maken.



Figuur 3 - Match in geografie en vermogen van P2H potentieel met offshore wind aanlanding[2]

[2] De weergegeven groei in aanlanding offshore wind is gebaseerd op de uitgeschreven tenders. Er lopen aanvullende initiatieven om de groei te versnellen van 1 GW naar 2 GW per jaar.



Figuur 4 - Afweging rond de inzet van hybride boilers

Op dit moment is nog slechts een fractie van het P2H-potentieel gerealiseerd, ondanks de goed uitontwikkelde en direct beschikbare technologie. De voornaamste redenen hiervoor zijn de investeringsdrempel om de bestaande gasinfrastructuur te vervangen door elektrische infra, en het bestaande kostenverschil tussen P2H-elektrificatie en het traditionele gasgestookte alternatief. Om het P2H-potentieel te ontsluiten is het noodzakelijk om dit kostenverschil weg te nemen. Het verschil kan weggenomen worden door een wijziging in de regelgeving of door directe financiële stimulering.

Het bedrijven van P2H-installaties kan op twee uiteenlopende wijzen plaatsvinden: op 'baseload' of flexibel. Bij flexibel bedrijf wordt een hybride systeem ingezet dat kan switchen tussen elektriciteit en gas om warmte op te wekken. Flexibel bedrijf is bijzonder geschikt voor het inpassen van offshore wind omdat de vraag het aanbod kan volgen. 'Baseload' bedrijf biedt het grootste potentieel om CO_2-emissies te reduceren, wanneer er duurzaam opgewekte elektriciteit wordt gebruikt. Een verstandig transitiepad zou zijn om te beginnen met het combineren van elektrische boilers met bestaande gasboilers in een geïntegreerd hybride systeem. Op het moment dat de bestaande gasboiler dan later afgeschreven wordt, kan de elektrische boiler verder op 'baseload' bedreven worden. In de toekomst kunnen deze boilers wellicht dan voor specifieke locaties weer worden vervangen door hoge-temperatuur warmtepompen, wanneer de technologie hiervan voldoende uitontwikkeld is.

Er bestaan meerdere overwegingen om het bedrijven van hybride boilers te optimaliseren:

- Economie; alleen elektriciteit gebruiken wanneer de prijzen lager zijn dan die voor gas, of
- Transportnet-support; switchen tussen elektriciteit en gas om overbelasting van het net te voorkomen, of
- CO_2-emissiereducite; zoveel mogelijk uren elektrisch bedrijf bij offshore windproductie

Gebaseerd op het huidige beleid en de voorziene marktontwikkeling zal P2H niet economisch rendabel worden, ongeacht de manier waarop de hybride boiler wordt ingezet.
Daarom zijn er aanvullende maatregelen nodig om kostenverschil weg te nemen tussen de hybride boiler en het aardgasgestookte alternatief.

Maatregelen om het kostenverschil weg te nemen met als doel de inpassing van offshore wind te bevorderen zouden zich moeten richten op het aanpassen van de transportnet tariefstructuur en subsidiëring van de investeringskosten. Voor het maximaliseren van de CO_2-emissiereductie is een subsidie die het prijsverschil tussen elektriciteit en aardgas wegneemt het meest effectief.
Met een toename van het aantal elektrische bedrijfsuren treedt er een verschuiving op in de kostenopbouw per elektrisch geproduceerde hoeveelheid warmte.
Bij een laag aantal P2H-bedrijfsuren worden de marginale kosten gedomineerd door de nettarieven en investeringskosten, terwijl bij een hoog aantal bedrijfsuren de commodity prijzen dominant worden.

Vanuit een systeembenadering is in dit rapport het optimale aantal P2H-bedrijfsuren bepaald op circa 4.500 uur per jaar.
Dit aantal komt overeen met het gemiddeld aantal vollasturen van een offshore windpark. Op deze wijze bedreven, sluit de elektriciteitsvraag van de P2H-unit aan bij de productie van nieuw geïnstalleerd wind-op-zee vermogen. Dit kan contractueel vastgelegd of middels marktprikkels gestimuleerd worden. De resulterende CO_2-emissiereductie bedraagt 4,5 Mt. Met de switch naar 'baseload' bedrijf kan de emissiereductie toenemen naar 9 Mt, wanneer er 100% duurzaam opgewekte elektriciteit wordt ingezet.

Op basis van analyses in dit rapport bedragen de totale kosten om het prijsverschil weg te nemen jaarlijks circa 250 MEUR voor een periode van 12 jaar, hetgeen overeenkomt met circa 60 EUR/ton CO_2. In 'baseload' bedrijf nemen deze kosten toe tot 170 EUR/ton CO_2. In grote lijnen zijn deze kosten verdeeld over drie posten: de transport tarieven, de benodigde investeringen in P2H-apparatuur en -infrastructuur, en de commodities (of verbruikskosten).

Mogelijke maatregelen om het prijsverschil weg te nemen kunnen op verschillende manieren worden ingestoken, maar deze zouden in ieder geval:

- P2H economisch realiseerbaar moeten maken voor de Nederlandse industrie
- De P2H elektriciteitsvraag afstemmen op de offshore wind productie
- Het kip-en-ei dilemma oplossen van de additionele vraag en de additionele productie, inclusief de match tussen de toename in de tijd van zowel vraag als productie
- Een eerlijke toewijzing van de CO_2-besparing bewerkstelligen

Aangezien in de industrie de geplande stops voor groot onderhoud in de regel om de zes jaar plaatsvinden met een planningsperiode tot 4 jaar vooruit, is implementatie van dergelijke maatregelen voor 2020 gewenst om de industrie hierop in te kunnen laten spelen. Gezien de nationale klimaatambities en het perspectief van de technologie lijkt het in ieder geval raadzaam om een aantal pilotprojecten rond elektrificatie in de industrie op te zetten om praktische ervaring op te doen met de afstemming van productie en vraag.

Als P2H op termijn met 100% duurzaam opgewekte elektriciteit wordt ingezet, kan met 'baseload' bedrijf de emissiereductie toenemen naar 9 Mt. Een dergelijke emissiereductie brengt zowel de industrie als de Nederland overheid naar realisatie van hun beider klimaatdoelstellingen, en betekent een grote stap naar een meer duurzame samenleving.

INTRODUCTION/ PERSPECTIVE

Dutch industry is facing the challenge to realize ambitious decarbonization targets while maintaining its global economic competitiveness. In the Netherlands, the Government has committed the country to an ambitious climate policy. In the 2017-2021 coalition agreement titled "Confidence in the Future" the ambition is expressed to become a sustainable country [1]. The coalition agreement subsequently states there is no alternative 'but to take decisive actions' to comply with the Paris climate agreement. In order to realize the ambitious targets, a national climate and energy agreement will be concluded with all parties in order to sharply reduce CO_2 emissions.

The national climate and energy agreement will give all stakeholders in society (companies, public authorities and environmental groups) more certainty about the long-term targets and establish a consultative platform where parties can engage in dialogue and respond to new developments in technology and other areas. Achieving 49% fewer emissions by 2030 would require an extra CO_2 reduction of 56 Mt on top of the current policy scenario. Based on foresight studies by the Netherlands Environmental Assessment Agency ('PBL') the coalition agreement provided an indication of the reduction allocation per sector. With 22 Mt, or 40%, a relatively large part of the reduction was allocated to industry. In a 2018 update by PBL [2] the 49% emission reduction requires a reduction of 48.7 instead of 56 Mt, and the industry allocation has changed from 22 to 14.3 Mt. The major contribution in this allocation is expected to be realized by industrial electrification. The table below provides both the coalition agreement sector allocation as the 2018 update which marked the starting point for the national climate and energy agreement.

The large allocation to the domain Industry in the reduction target can be motivated by an equally large share in the Dutch CO_2 emissions. In 2014, more than 40% (or 67 Mt) of the carbon dioxide emitted in the Netherlands came from Industry's processes (or direct emissions) and its use of electric power (or indirect emissions) [3]. Since the Dutch industry has already lowered its greenhouse gas emissions with 32% in the period from 1990 to 2014 [3], it will require a considerable joint effort to achieve a comparable additional emission reduction; The 'low-hanging fruits' or 'quick wins' have already been collected, leaving the more difficult and/or expensive measures to be implemented.

Furthermore, most of the energy-intensive industrial companies operate in highly competitive international or global markets. Combined, this makes a demanding challenge for the Dutch industry to realize the decarbonization targets while maintaining its global economic competitiveness. Two recently published future outlooks, the McKinsey report [4] and the VNCI roadmap [5], agree on the necessity of governmental support to maintain a level playing field for the Dutch industry. As stated in the coalition agreement: "An adaptive, innovation focused policy package can safeguard the competitiveness of Dutch industry and build on the Netherlands' strengths. Good climate policy based on smart principles creates opportunities for economic growth and employment", "The Renewable Energy Grant Scheme (SDE+) – and the associated storage of sustainable energy – will be continued and expanded" and "Doing so will at the same time reduce our dependence on Middle Eastern oil and Russian gas."

Sector	Allocation indication in 2017 coalition agreement	2018 Update in allocation indication	Emissions in 2030 following climate agreement
Industry	22	14.3	35.7
Transport	3.5	7.3	25.0
Built environment	7	3.4	15.3
Electricity	20	20.2	12.4
Land use and agriculture	3.5	3.5	22.2
TOTAL	56	48.7	110.6

Table 1 - Table with sector allocations of emission reduction (all numbers in Mt CO_2) as taken from [2] Kamerbrief "PBL-notitie 'Kosten Energie- en Klimaattransitie in 2030 - update 2018'"

Electrification of industry: P2H, P2G & P2X

In the sector allocation update [2] electrification of industry is presented as an option that can contribute significantly towards achieving the national emission reduction targets. The concept behind this electrification is that the consumption of fossil fuels or feedstocks is replaced by renewable electricity, either direct or indirect. An example of direct replacement is the application of an electric boiler, a direct electrode boiler or a hybrid boiler where steam is directly generated using electricity. This application of, preferably renewable, electricity is often referred to as Power-to-Heat or P2H.

An example of indirect replacement is the application of hydrogen gas produced from electrolysis, where the hydrogen is used as a fuel stream. This application of, preferably renewable, electricity is often referred to as Power-to-Gas or P2G. When the hydrogen is applied as feedstock and together with a CCU-stream converted to products this is often referred to as Power-to-(unspecified)-Products or P2X. Finally, in some circles the acronym P2P stands for Power-to-Power or (electricity) storage.

Combined there are multiple options where the consumption of fossil hydrocarbons in industry can be replaced by electricity. Together the options provide a significant emission reduction potential. This important potential is confirmed in several reports recently published on the subject on electrification [6], [7], [8] and [10].

Additional motivation over the emission reduction target for the application of electrification in industry is the desired reduction of the natural gas consumption. Given the recent events in the province of Groningen, the resulting appeal to reduce the low-calorific gas usage in industry and the geo-political concerns with a dependency on Russian gas, there is strong motivation for this reduction coming from government.

However, since the commodity prices for electricity are generally almost double those for gas, the business cases for industrial electrification are unfavorable. As a result, the current application of these techniques is rather limited. A serious research and development effort is required before most of the aforementioned options can be technically implemented at full scale in the process industry with confidence. A possible exception is the P2H technology, which is relatively simple and already has multiple successful large scale applications in for instance Danish district heating systems. Often power-to-heat boilers are not directly connected to the primary processes but are part of the supporting utilities. Because of this, ‘power-to-heat’ can be regarded as a technology with the potential to play a prominent role in the coming years. This view is in line with the conclusions from the McKinsey report where electrification of heat demand has been given the largest reduction potential. Both P2G and P2P carry a large potential for the longer term, since the technology transport and storage infrastructure still have to be developed and organized.

STIMULATING RENEWABLES

The second priority in the national climate policy is a rapid increase in the share of renewables in the electricity production. While a scheme is developed to phase out the existing coal-fired power plants, the different renewable options are stimulated to grow. Solar photovoltaic, both small scale on individual houses and in multi-MW commercial PV-farms, onshore wind energy and, especially, offshore wind energy show a spectacular increase in anticipated installed capacity.

In a recent letter from the Ministry of Economic Affairs and Climate to the Dutch House of Parliament (Kamerbrief "Routekaart windenergie op zee 2030", March 27, 2018) the planned realization in offshore wind power is described [9]. Up to the year 2026, the annual capacity increase is equal to 700 MW and from 2027 onwards the annual increase is expected to grow to 1,000 MW, as illustrated in figure 5. The actual growth in installed offshore wind might well be larger than these governmental plans since additional initiatives are currently discussed to increase the annual growth to 2,000 MW.

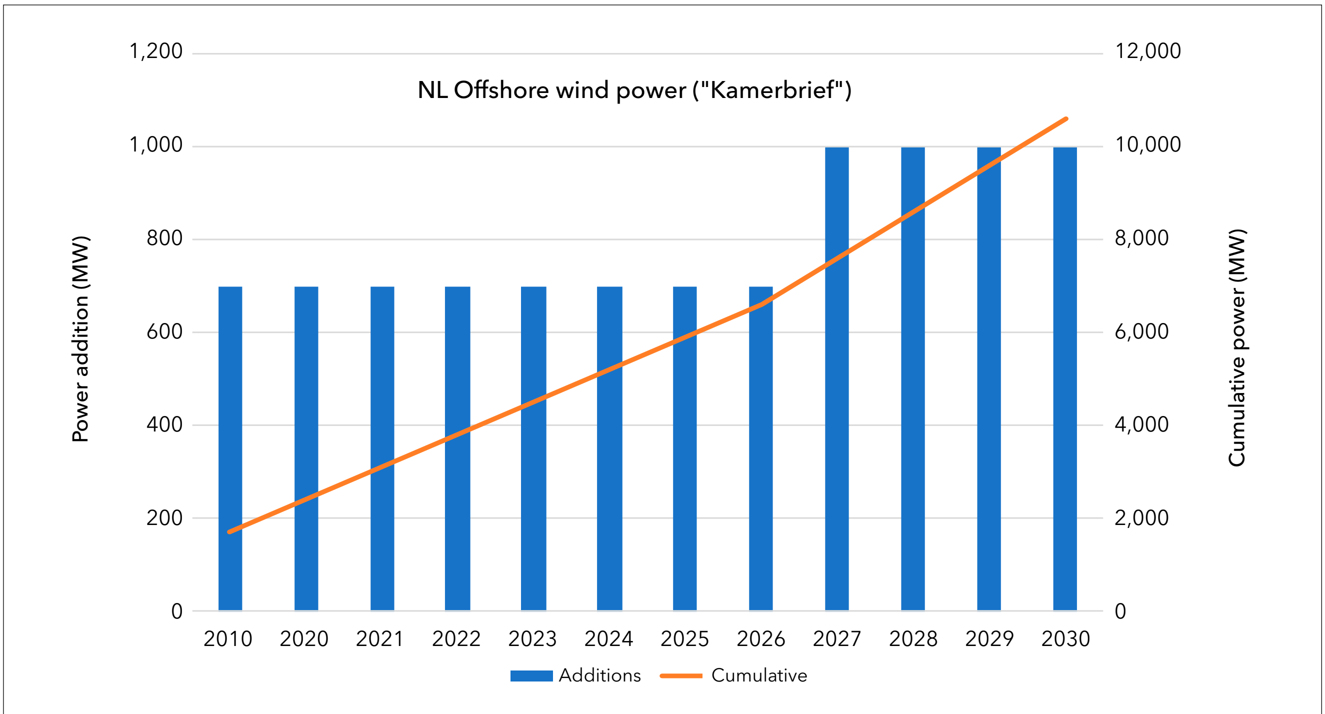


Figure 5 - The planned realization in offshore wind power (numbers based on [9])

Offshore windfarm	Tender	Realization	Power (MW)	Cumulated power (MW)	Electricity produced (GWH)	Production as share of 2016
Existing		2018	1,000	1,000	4,500	3.8%
Borssele 1+2	2016	2019	700	1,700	7,650	6.4%
Borssele 3+4	2016	2020	700	2,400	10,800	9.0%
Hollandse Kust Zuid 1+2	2017	2021	700	3,100	13,950	11.7%
Hollandse Kust Zuid 3+4	2018	2022	700	3,800	17,100	14.3%
Hollandse Kust Noord 1+2	2019	2023	700	4,500	20,250	16.9%
Hollandse Kust West 12	2020	2024	700	5,200	23,400	19.6%
Hollandse Kust West 12	2021	2025	700	5,900	26,550	22.2%
Ten Noorden vd Wadden	2022	2026	700	6,600	29,700	24.8%
IJmuiden Ver 1	2023	2027	1,000	7,600	34,200	28.6%
IJmuiden Ver 2	2024	2028	1,000	8,600	38,700	32.4%
IJmuiden Ver 3	2025	2029	1,000	9,600	43,200	36.1%
IJmuiden Ver 4	2026	2030	1,000	10,600	47,700	39.9%

Table 2 - Anticipated year of realization for the different offshore wind farms [9]

Table 2 indicates the anticipated year of realization for the different off-shore wind farms. Additionally, the cumulative installed capacity in offshore wind power is given, as well as the expected quantity of electricity produced. To place this quantity in perspective, the electricity production from the off-shore wind farms is also expressed as the share of the 2016 national electricity consumption. In 2018 the share of offshore wind is only a modest 3,8%, but this share is expected to grow to a spectacular nearly 40% in 2030 following the national renewable energy ambition.

The location of the different wind farms listed in the table can be found on the map from the North Sea with the existing wind farms (in red), the wind farms projected up to 2023 (in blue), the wind farms projected up to 2030 (in green) and possible future locations (in yellow). The 12-mile coastal zone is indicated with the dashed line.

The offshore wind farms with a planned realization date before 2027 will be directly connected to the national grid with subsea cables that come onshore in the coastal regions, like the existing wind farms. More specifically, these cables will come ashore near Borssele, Hoek van Holland, Velsen and Eemshaven (form south to north). For the more remote offshore wind farms planned after 2026, like IJmuiden Ver, the design for the connection to the grid has not been finalized yet. To avoid congestion alternatives are sought for the coastal zone connections. One of the options is an HVDC (high voltage direct current) cable that connects to the grid at locations further inland. Another option, especially in the longer run, is the creation of an artificial island where power is stored and/or converted to hydrogen and transported onshore using (existing) gas-infrastructure. The picture below (figure 6) presents an artist impression of such an island (picture taken from the TenneT website).

Figure 6 - Artist impression of the artificial island (source: TenneT)

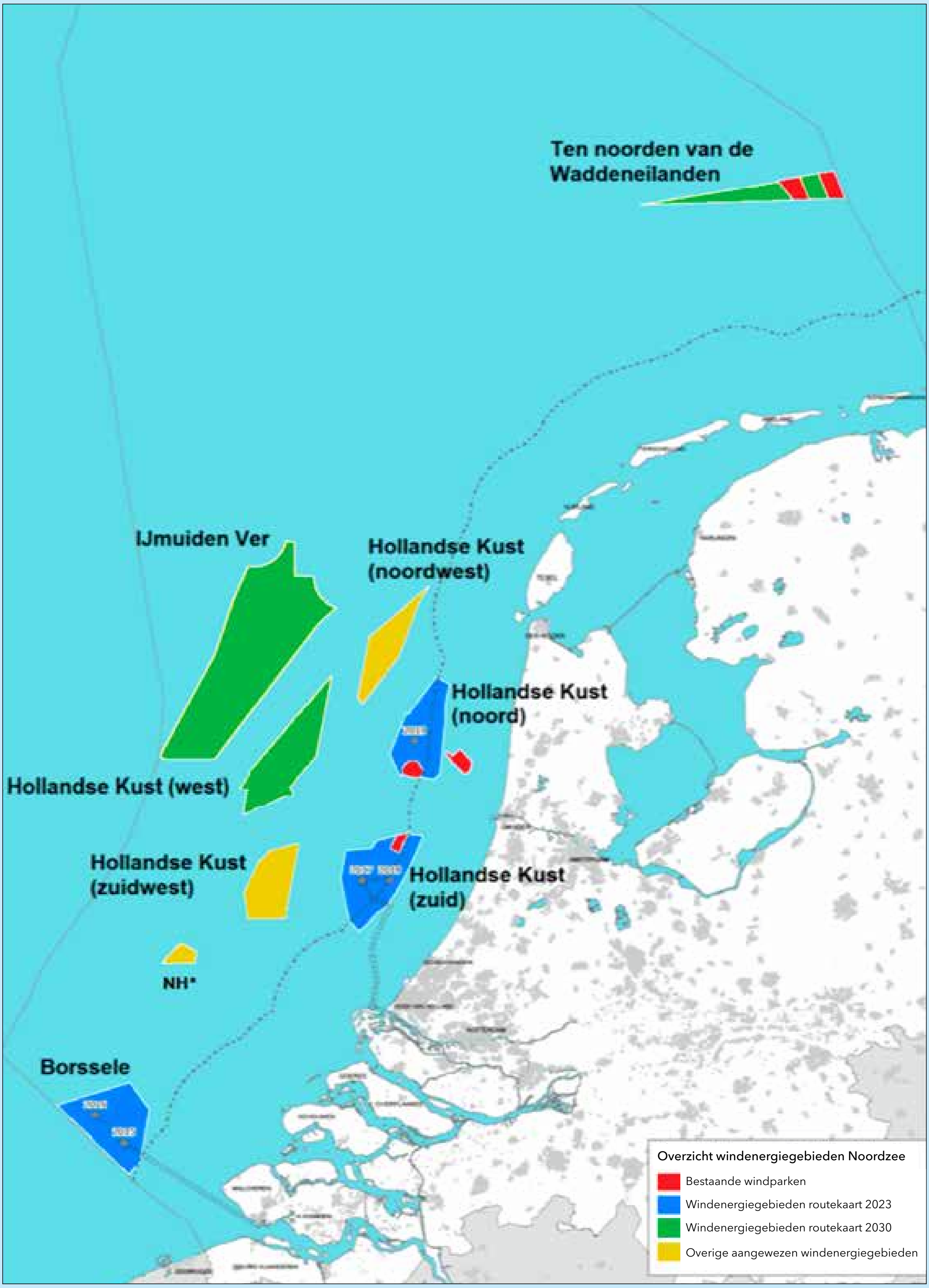


Figure 7 - The location of the offshore wind farms in the North Sea with the existing wind farms (in red), the wind farms projected up to 2023 (in blue), the wind farms projected up to 2030 (in green) and possible future locations (in yellow) (map taken from [9])

From power to energy

With the rapid increase in installed offshore wind power the amount of electricity produced will also rapidly increase. The combined dimensioning of the rotor diameter and generator capacity for modern wind turbines is such that the turbine can deliver 4,500 full load hours annually on average. Although the number of full load hours is impressively high, the wind turbines will not permanently deliver power but follow a variable load profile. The power duration curves for the installed offshore wind farms over the years is given in figure 8.

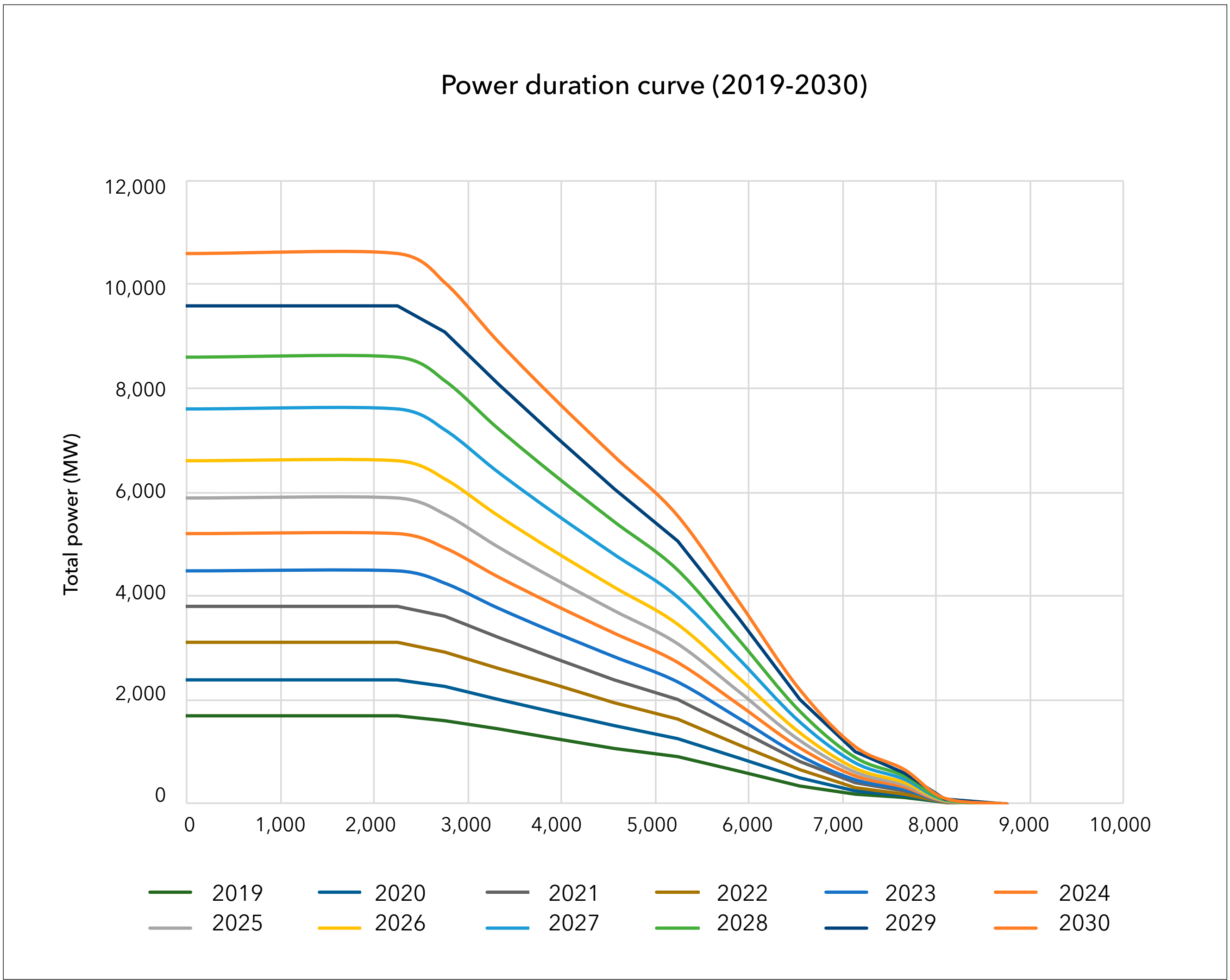


Figure 8 - The power duration curves for the installed offshore wind farms over the years

The generated power at any given moment is mainly controlled by the instantaneous meteorological conditions. With the increase in installed offshore wind capacity this creates two challenges:

- Due to the not-perfectly power production from wind turbines unforeseen peaks might occur. These peaks create a 'MW' issue in the national electricity grid.
- The large installed capacity in offshore wind creates a surplus of electricity that does not always match the available demand. This surplus creates a 'MWh'-issue on the electricity market.

The peak MW-issue is expected to occur during a couple of hundred hours annually. When the initial initiatives for the rollout of up to 30 GW or 76 GW in offshore wind production are realized, the MWh issue could potentially increase significantly. To accommodate these quantities of renewable energy three, rather different, options are feasible.

1. **Curtailment:** when the peak power cannot be transported due to cable limitations in the grid, or when there is no matching demand for the power produced, the wind turbines are switched off. This option would result in lost carbon reduction opportunity.
2. **Grid reinforcement:** the grid transport capacity can be increased to facilitate the transport of peak power production to locations where this power can be utilized and/or exported. Expensive reinforcement for incidental power peaks is likely to be economically inefficient.
3. **Industrial electrification:** additional electricity demand close to the landing locations could be realized which would reduce the strain on the tranport grid further inland.

The option of additional electricity demand could make a perfect combination with the current incentive towards electrification of industry as industry is likely to provide the necessary scale and volume in demand to match the massive anticipated growth in renewable production power.

MATCH AND TIMELINES

The current incentive towards the electrification of the heat production (P2H) in industry combines well with the massive anticipated growth in renewable production power; industrial electrification is both dependent on, but may also facilitate the growth in renewables.
The first element in this positive match is the geographic location. There is an almost perfect match between the locations where the off-shore windfarms that will be realized up to 2026 are connected to the national electricity transport grid, and four of the locations where the Dutch industry is concentrated. These four coastal industrial concentration spots or 'clusters' as they are often referred to, are (from south to north):

- Zeeland
- Rotterdam Moerdijk
- Noordzeekanaalgebied
- Noord NL

The fifth industrial cluster, Chemelot, is located on the southernmost spot inland in the Netherlands.

The next step in the match is the assessment of the likely potential for P2H at the industry clusters and check how these numbers compare with the wind power that is fed into the grid at those locations over time. The detailed assessment is provided in this section and the calculated P2H-potential in the clusters are presented in table 5.

The assessment is based on the NEA (Netherlands Emission Authority) ETS figures over the year 2016[3].

After deleting 380 of the smallest emitters (<0,1% total each) some 87 sites remain, representing 93% of the total 2016 emission of 93.9 Mt CO_2.

These emitters are divided over the 5 industry clusters and an additional separation is made between the emissions that are strictly related to electricity production and the direct or 'real industrial' emissions. The results are summarized in table 3. (The percentages are given for the five clusters for easy comparison.)

	NEA (ton CO_2)		Share E-production		Industrial emission	
Chemelot	5,036,785	6.4%	0	0.0%	5,036,785	13.4%
Noord NL	12,888,729	16.5%	11,789,979	29.1%	1,098,750	2.9%
Noorzeekanaalgebied	17,061,664	21.8%	10,763,215	26.5%	6,298,449	16.8%
Rotterdam Moerdijk	32,277,211	41.3%	16,582,118	40.9%	15,695,093	41.8%
Zeeland	10,863,628	13.9%	1,418,460	3.5%	9,445,168	25.1%
'Elsewhere'	9,037,916	11.6%	5,736,559	14.1%	3,301,357	8.8%
Summation	**87,165,933**	**111.6%**	**46,290,331**	**114.1%**	**40,875,602**	**108.8%**

Table 3 - 2016 NEA emission figures sorted for the 5 industry clusters

[3] https://www.emissieautoriteit.nl/documenten/publicatie/2017/04/03/voorlopige-emissiecijfers-industrie-2013-2016

	NEA-figures (kton CO_2)		GWh/year	PJ/year
Chemelot	5,037	13.4%	24,800	89.1
Noord NL	1,099	2.9%	5,400	19.4
Noorzeekanaalgebied	6,299	16.8%	31,000	112
Rotterdam Moerdijk	15,695	41.8%	77,200	278
Zeeland	9,445	25.1%	46,400	167
'Elsewhere'	3,302		16,200	58.4
Summation	**40,876**	**100%**		**723**

Table 4 - Annual emission numbers converted to energy for the 5 industry clusters

These annual emission numbers are converted to energy under the assumption that the vast majority of the energy was supplied as natural gas (with the standard emission factor of 56,5 kg/GJ). With the energy quantities expressed both in GWh and PJ the results are given in table 4. The calculated total of 723 PJ compares well with the total industrial heat demand of 563 PJ (78%) as given by Blueterra [11], since the heat demand in industry on average makes up about 80% of the (direct) industrial emissions [12].

To make a first order assessment of the Power-to-Heat potential within the five Dutch industry clusters a series of assumptions had to be combined. In a recent questionnaire, the VNCI generated insights in the industrial heat demand [13]. One of the results was that the indirect heat demand (using steam as heat transfer medium) was just over 40% of the total, with direct heating using furnaces etc. making up the remaining 60%. Especially for the indirect heat demand it is likely that the steam boilers can be replaced by electric boilers or can be converted to hybrid boilers. From the direct heat demand, only 3% was supplied using CHP (combined heat and power), whereas from the indirect heat demand about 75% was generated with CHP.

To produce 100 units of heat using an industrial CHP (eff_e = 35%, eff_h = 50%) takes 200 units of energy while simultaneously producing 70 units of electricity.
The production of 100 units of heat with an efficient boiler requires 105 units of energy. With the replacement of a CHP or a gas boiler unit by an electric boiler for the same quantity of heat, the resulting increase in electricity demand and reduction in CO_2-emission are different for the CHP and boiler unit.

Replacing a CHP by P2H increases the electricity demand with (70 + 105 =) 175 units, whereas replacement of a boiler takes 105 units. The 'CHP-factor' is equal to (175/105 =) 1,67. Weighted for a 75% CHP share this becomes 1,5. For the CO_2-emission reduction this factor becomes 1,9 (or weighted 1,68).

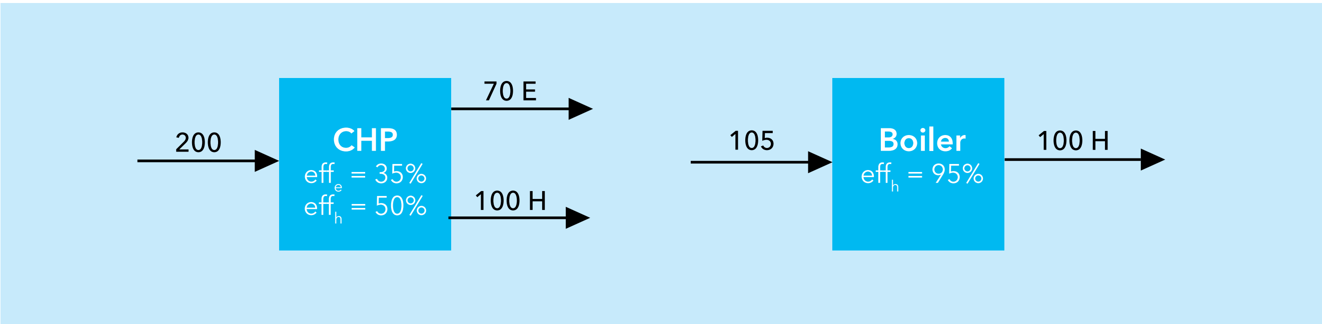


Figure 9 - Relevant energy streams when replacing a CHP-unit or a gas-fired boiler with an electric boiler

Not all boilers or CHP-units can be replaced by Power-to-Heat units since these units are sometimes tightly integrated in the primary process. For example, when a waste (gas) stream out of the process is burned in the unit, replacement by P2H requires additional process modifications. When for environmental or technical reasons (like odor or safety) the combustion air is a ventilation air stream from process or storage areas, replacement by P2H requires also additional process modifications. By lack of detailed numbers the conservative assumption is that 50% of the heating units cannot be replaced due to tight integration. Another assumption is that 25% of the CHP-units are used with direct mechanical drive which make them far more complex to replace, leaving 75% of the CHP's replaceable (or 80% weighted for all indirect heating units).

Using this set of derived numbers the potential for P2H can be calculated from the 'emission figures energy quantities' as calculated before [expressed in GWH_{th}/yr]. Given the 80% share of total direct energy demand for heating, the 40% share of the heating demand for indirect heating (which can most easily be electrified by P2H), the 50% share for 'process integrated' heating units, and finally 80% share for the non-mechanical drives CHP's the potential P2H power can be calculated using the CHP factor as

(80% * 40% * 50% * 80% * 1,5 = 12,8% * 1,5 =) 19,2%

A final assumption is that the full P2H potential as calculated can only be realized in some six to eight years from now due to planned turn-arounds, design, instrumentation and manufacturing issues, etc.
An optimistic view is that in the coming three years the first 15% of the P2H potential can be realized as pilots and retrofits, and another 15% can be added in the intervening years 2021-2023.

Cluster	P2H Power in MW		
	2018-2020	2021-2023	2024-2026
	15%	30%	100%
Chemelot	81	160	540
Noord NL	18	36	120
Noorzeekanaalgebied	100	200	680
Rotterdam Moerdijk	250	510	1,690
Zeeland	150	310	1,020
Summation	**660**	**1,320**	**4,410**

Table 5 - Calculated P2H potential for the 5 industry clusters and development in time

The calculated P2H power potentials in table 5 are first assessment values and therefore carry some inevitable uncertainty. However, these results should be regarded as clear indicators that the electrification of the heat demand in industry can create electricity demands that are significant to match the quantities from offshore wind. The about 1,700 MW in the Rotterdam area, the 1,000 MW in the Zeeland cluster and the 700 MW in the 'Noordzeekanaalgebied'-cluster of P2H potential are robust contributors to absorb the surplus production of offshore wind electricity. This capacity is of course not available today, but when the economic perspectives would be ensured, the P2H development is likely to keep pace with the increase in offshore wind. On the longer run continuous electrification in industry could keep pace with wind power development. The good match in both location, quantity and time has been visualized in the two plots on page 27. The top plot shows the development in time of the P2H power for the five industrial clusters in the Netherlands. The bottom graph shows the power that comes on shore in the same 5 cluster locations.

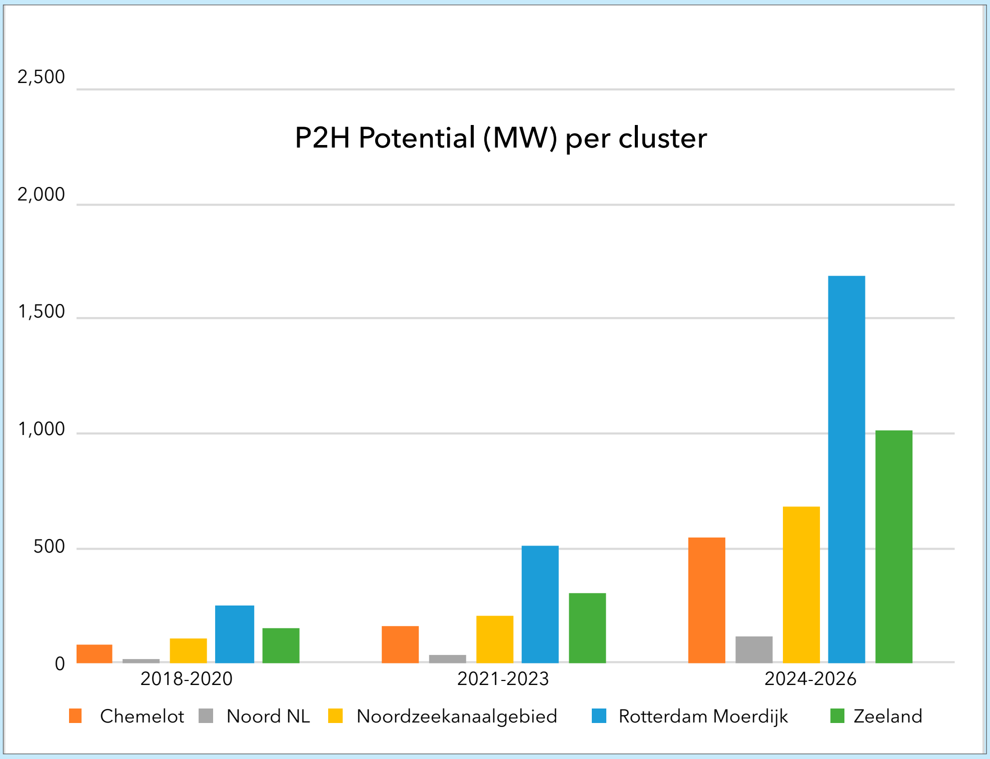


Figure 10 - Development in time of the P2H power for the five industry clusters in the Netherlands

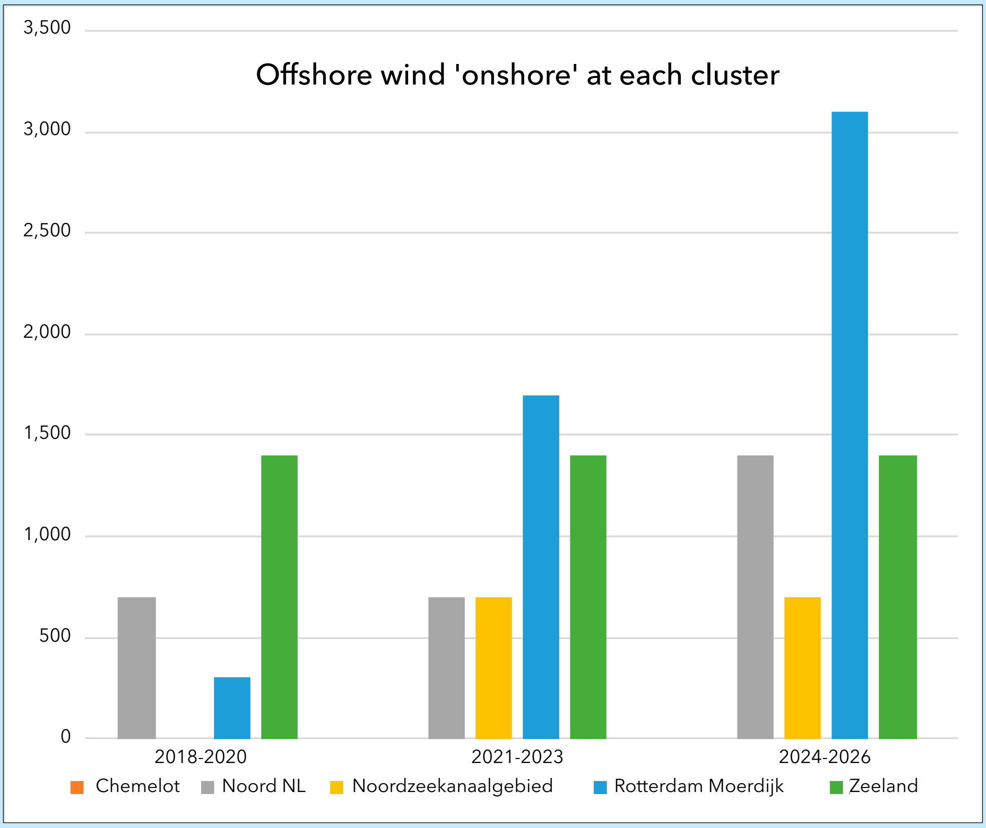


Figure 11 - The offshore wind power that comes onshore in the 5 industry cluster locations

MOTIVATION, SOCIETAL BENEFITS

Two priorities in the national climate policy have been described in the preceding chapters:

- the emission reduction by electrification of heat production (P2H) in industry, and
- a growth in renewable production power, especially offshore wind

Together these two incentives with their demonstrated match in both location, quantity and timing, can significantly contribute to a series of important societal benefits:

1. **A reduction in the fossil fuel consumption**
   A reduced use of natural gas is completely in line with the current climate ambitions but also desired from the recent developments in Groningen and for geopolitical reasons.

2. **Reduced CO_2-emissions**
   The increasing electrification in industry can make an impressive contribution to the emission reduction. This potential is only obtained when renewable energy is used as driving power; application of fossil fueled power would increase the emissions.

3. **Avoided grid reinforcement**
   The grid transport capacity doesn't have to be increased to facilitate the transport of peak power production to (remote) locations when this power can be utilized in the industry clusters near the coast. Grid reinforcement for incidental power peaks is expensive. The local distribution grid however, might have to be reinforced to accommodate the additional capacity.

4. **Avoided curtailment**
   With the additional, flexible power demand from electrification in industry there is no need to switch off the offshore wind turbines.

5. **Additional RES integration**
   With additional demand for renewable energy from electrification the share of renewables increases in the supply mix. This increased share of renewables positively influences the capture price for renewable energy sources, which improves the business case by both preventing and reducing (market based) curtailment.

The first four societal benefits will be discussed and quantified in the next paragraphs of this chapter.

Reduced fossil fuel consumption

The assessment of the P2H potential power in industry resulted in a value of 4,405 MW with 8,760 operating hours annually. Without electrification, a similar quantity of energy has to be generated by burning mainly natural gas. Applying the CHP-CO_2-correction factor of (1.68/1.5=) 1.12 (see the CHP-replacement discussion in the previous chapter) results in an equivalent natural gas consumption of 4.9 billion m^3. To put this quantity in some perspective: this gas consumption corresponds to about 6% of the Dutch national gas production (with an annual natural gas production of 80 billion m^3 according to CBS). Since it was already demonstrated that the P2H-potential made a match to the planned offshore wind power, also the potential reduction in natural gas consumption through industrial electrification can make an important societal benefit.

Two important remarks should accompany this important result:

- The numbers indicate potential savings, in case P2H can be fed using 100% renewables. The fuel mix used during operation should be taken into account to determine actual savings. This will be discussed in more detail in the next chapter.
- The assessment of the potential P2H power was limited to only a reduced part of the indirect (or 'utility') heat generation in industry. With the anticipated progress in both technology and market conditions the potential for electrification in industry might well increase.

Reduced CO_2-emissions

The assessment of the equivalent natural gas consumption reduction of 4.9 billion m^3 can easily be converted to the potential CO_2 reduction through industrial electrification using the specific emission for natural gas of 56.5 kg/GJ. The calculated **potential** CO_2 reduction is equal to a quantity of 8.8 Mt CO_2 per year, if P2H systems can be fed using **100% renewables**.
To put this quantity in some perspective: this annual CO_2 emission reduction corresponds to about 20% of the Dutch direct industrial emissions, making it an important potential societal benefit. Currently, feeding P2H with 100% renewables is not feasible. The amount of CO_2 savings that can be realized in the short term will be calculated as part of the business case in the next chapter.

The same two important remarks as in the previous paragraph should accompany this important result:

- it is a necessary requirement that the additional demand created by P2H is matched by an overall increase in renewable production of the same size
- the potential for electrification in industry might well increase

Avoided grid reinforcement

With the rapid anticipated increase in offshore wind power the national transport grid would be seriously challenged to transport all the produced electricity to the locations with demand, certainly in periods of peak wind production. Congestion issues could delay the development of further offshore wind production.
The current estimate is that the transport grid can handle up to 6 GW of offshore wind feed-in in coastal locations, and 10 GW when connecting part of production further in-land. This is slightly lower than the currently planned 11 GW in production up to 2030.

While the 11 GW in planned production could already impact the transport grid, future expansions are currently being considered. There are initiatives to increase the planned capacity for 2030 to 17 GW or even 30 GW, going up to 76 GW after 2030. This would put a significant strain on the transmission grid. These targets would also require to increase the capacity growth from 1 GW of additional capacity per year to 2 GW. Not only does this lead to significant investment costs in the transmission grid, but it also introduces the risk that necessary grid expansions and reinforcement can't be realized in time due to long lead times and planning risks for transmission infrastructure. Increasing demand for electricity in areas where offshore wind is fed into the transmission grid can reduce the strain on the grid, and by doing so prevent costs or buy the time necessary to get the transmission grid ready for the future. In addition to the national transportation grid, large additional loads might create congestion on the local electricity transportation and distribution grids, which in some regions are already heavily loaded. These challenges at a local level should be considered in planning activities.

Avoided curtailment

Analyses have been performed to make a first order assessment of the curtailment that might occur with the anticipated increase in off-shore wind generation of 11 GW up to 2030. A distinction is made between grid based curtailment, where the capacity of the transport grid is insufficient (MW issue) and market base curtailment, where more energy is produced than can be sold on the market (MWh issue).

- **Grid-based curtailment** was calculated based on PLEXOS based production profiles for the total offshore wind portfolio in the Netherlands. For the calculation, the grid limit was assumed to be 10 GW on a copper-plate level, therefore not taking into account individual lines and cables. Based on 11 GW in production capacity, the share of the production that can't be transported due to transport grid limitations, is equal to 4,230 GWh. This corresponds to 12% of the total in offshore wind generation. The curtailment will occur during 422 hours over the year, which corresponds to 4.8% of all hours. This could increase significantly when the growth of offshore wind increases to 17, 30 or even 76 GW. It should be noted that this calculation is based on production of the entire offshore portfolio of the Netherlands and assumes the grid limit as a 10 GW copper plate. In practice, grid based curtailment will be based on production in much smaller geographical areas, where simultaneity of wind speeds is much higher. As a result, grid based curtailment could occur whenever wind farms are producing at (close to) their rated power - which happens at an average of 2,250 hours per year, in accordance with the power duration curve in figure 8.
- **Market-based curtailment** was calculated using PLEXOS simulations for 2030, assuming 11 GW in offshore wind production. The total share of the production that can't be sold on the market under these conditions is equal to 6.5 GWh. This corresponds to 0.02% of the total offshore wind generation. The share of market based curtailment is relatively low, as a result of interconnections and market coupling with Germany and Belgium. These countries can absorb the surplus power production. When the growth in off shore wind power would exceed 11 GW, the market based curtailment is expected to increase due to limitations in interconnection capacity. No simulations were performed for cases with 17, 30 or 76 GW in offshore wind.

These curtailment assessment results indicate the demand for additional, flexible power demand. With the realization of the P2H-potential the electrification in industry could reduce the need to switch off the offshore wind turbines, especially to prevent grid-based curtailment. This can lead to further reductions in CO_2 emissions, as the curtailed renewable generation would not have to be replaced with non-renewable generation. Additionally, the additional renewable production could reduce the average wholesale electricity market price, which would in turn benefit the rollout of further electrification initiatives.

COST ASSESSMENT OF P2H IN INDUSTRY

As has been shown in the previous chapters, there is significant potential for electrification of industrial energy consumption in the Netherlands through the application of P2H. However, this potential has remained unrealized. In order to identify the underlying issue that is preventing this potential from being unlocked, business cases were calculated for a hybrid boiler under different operating regimes. These business cases included a Net Present Value (NPV), as a measure of the total investment necessary from industry in these alternatives, and €/ton CO_2 saved as a measure of competitiveness in comparison to other measures of achieving CO_2 reduction. Additionally, a sensitivity analysis was performed to identify how this cost gap could be influenced by financial incentives or regulatory change.

In conclusion: There is a significant price gap between P2H and the gas fired alternative, regardless of how P2H is operated. When operating P2H for providing grid support, the cost gap is dominated by grid tariffs and investment costs. Operation that maximizes CO_2 emission reduction is dominated by costs of commodities (electricity, natural gas and CO_2).

This chapter starts with an introduction of the scope and assumptions used for the business case, before going into detail on the economics. The chapter finishes off with a sensitivity analysis.

Scope

A business case was calculated for a number of P2H technologies. In order to compare the results to the existing situation, a reference case for a gas boiler was initially established. This case was based on the following parameters:

- 15 MW_{th} boiler system for supplying steam
- Utility, so not integrated into the primary process
- No suitable grid connection available

The base case will be contrasted with a situation where an electric boiler is added to the existing gas boiler, creating a hybrid system that can flexibly switch between natural gas and electricity as source of fuel.

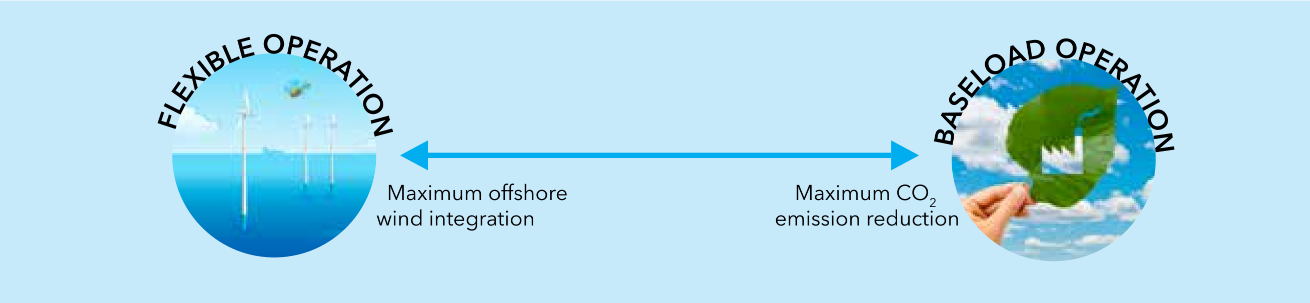
Full replacement of the gas boiler with an electric boiler or high-temperature heat pump are not considered in this report. Large scale replacement of existing infrastructure with electric boilers is unlikely in the short term due to the remaining lifetime. High temperature heat pumps are currently too expensive to be a viable alternative outside of niche applications.

Hybrid boiler scenarios

The operations of P2H facilities can be characterized between the two modes: baseload- or flexible use. The latter implies using hybrid systems that can switch between electricity and gas for the supply of heat. Flexible operation is most suited for facilitating offshore wind integration, as demand can be matched to supply. Baseload operation has the highest potential for CO_2 emission reduction, when supplied with 100% renewable generation.

It is possible to optimize operation of hybrid boilers based on:

- Economics, utilizing electricity only when prices are lower than gas prices, or
- Grid support, switching between electricity and gas in order to avoid congestion, or
- CO_2 reduction, maximizing the amount of electrically operated hours during offshore wind production



For the purpose of this study, four operating scenarios for the hybrid boiler will be considered:

- **Market optimization:** Based on modelling of electricity and gas prices, the number of hours operated electrically is around 450 in 2020. This number rises to around 1,200 in 2030.
- **Wind integration:** As outlined in the previous chapter, the transport grid is capable of integrating about 10 GW in offshore wind production. By operating P2H at times of production levels >10 GW, integration can be facilitated. Based on the power duration curve in figure 8, this would amount to about 2,250 hours annually.
- **Renewable integration:** The maximum amount of offshore wind energy produced can be captured by operating electrically during the amount of offshore wind full-load production equivalent, which is around 4,500 hours annually.
- **Baseload:** Operating 100% electrically, or 8,760 hours annually.

Parameters and assumptions

The business case will make use of calculations and assumptions for CAPEX, OPEX and fuel costs for each of the four systems studied. The different parameters used and assumptions for their values are outlined in the following sections. The business case will consist of the Net Present Value (NPV) of the four hybrid scenarios, which will be compared to the gas boiler base case. The NPV will consist of the following components:

- CAPEX: investment costs
- OPEX: recurring operational expenses, excluding fuel
- Fuel costs: including taxes and ETS-based CO_2 costs

For calculation of the final business case a 12-year lifetime and an 8% yearly discount rate were used. Based on the difference in NPV between P2H and the base case, a cost gap was identified. The cost gap, which is indicative of the additional costs necessary to realize P2H under the different operation scenarios, was used in combination with the total CO_2 savings to determine the cost in €/ton CO_2 of emission reduction.

CAPEX

In this section the necessary investment costs for purchase and installation of the different utility heat supply systems are outlined. Estimates and calculations are rounded off to the nearest 100 kEUR. There is no difference in CAPEX assumed between the different hybrid boiler scenarios.

Equipment costs

Investment costs for the full engineering, procurement and construction of heat supply systems including civil works. Cost estimations were based on data provided by Akzo Nobel and DNV GL market data. Equipment costs are circa 25% of total engineering, procurement and construction (EPC) costs. Due to utilization of an existing gas boiler system, investment costs for the base case are assumed to be zero.

Grid connection

Costs for the new grid connection that are to be paid by the owner of the heat supply system. Above 10 MVA, which is what the electric and hybrid systems will require, connections costs are custom and require a case-based quotation. These costs will differ based on the distance to the nearest transformer with spare capacity, as well as the type of connection required for this transformer. Estimations used are on the low end of the potential cost range, as industrial clusters typically have relatively dense grids. Industrial users that are not located near transformer stations with a connection opportunity available could incur significant additional costs, as total connection costs are mainly dependent on distance. For the gas boiler base case, existing infrastructure will be utilized and grid connection costs are assumed to be zero.

	Gas boiler	Hybrid boiler
Equipment costs	-	- 2.6
Grid connection	-	- 0.5
Total CAPEX	**-**	**- 3.1**

Table 6 - CAPEX figures (in MEUR)

	Gas boiler	Hybrid boiler
Fixed O&M	- 0.1	- 0.1
Variable O&M	- 0.5	- 0.5
Connection tariff	-	- 0.5
Supply fee	-	- 0.3
Contracted capacity	- 0.3	- 2.0
Transport tariff	-	- 2.5
Total OPEX	**- 0.9**	**- 5.9**

Table 7 - OPEX figures (in MEUR over the system lifetime)

OPEX

In the section below the necessary investment costs for purchase and installation of the different utility heat supply systems are outlined. Public cost data from distribution system operators was used where possible. The type of connection used was based on the assumption that the system would be operated by consumer with a large existing demand for electricity. Estimates and calculations are rounded off to the nearest 100 kEUR. No difference in OPEX is assumed between the different hybrid boiler scenarios.

Fixed O&M

Yearly maintenance cost during operation, assumed to be about 2% of equipment costs. The hybrid system is assumed to be integrated, and therefore doesn't incur double O&M costs.

Variable O&M

Maintenance cost dependent on utilization, assumptions are based on DNV GL market experience.

Connection tariff

Fixed yearly fee, based on connection size. Fee is custom for connections >10 MVA, because of which an approximation was used for the hybrid boiler. For the gas boiler, these costs are negligible.

Supply and metering fee (or "vastrecht")

Fixed yearly fee for metering and electricity supply. Height of the fee is dependent on the grid level to which the cable is connected. Prices used are from Alliander for HS/MS or TS connections [14]. For the gas boiler, these costs are negligible.

Contracted capacity

Monthly or yearly fee for the maximum capacity that is to be supplied using the connection. In case the actual maximum demand exceeds the contracted capacity, the contracted capacity will be increased. Contracted capacity is priced per kW and dependent on the grid level to which the cable is connected. Price data from Alliander for G1600 (gas) and HS/MS (electricity) connections was used [14].

Transport tariff

The transport tariff is meant to cover losses and other transport related costs that are incurred by the TSO and DSO as a result of transporting electricity to the consumer. As losses increase with capacity, transport tariffs are priced based on the maximum demand in kW per month. Again, this component is dependent on what grid level the cable is connected to. Price data from Alliander for HS/MS connections was used [14].
For natural gas, there is no transport tariff.

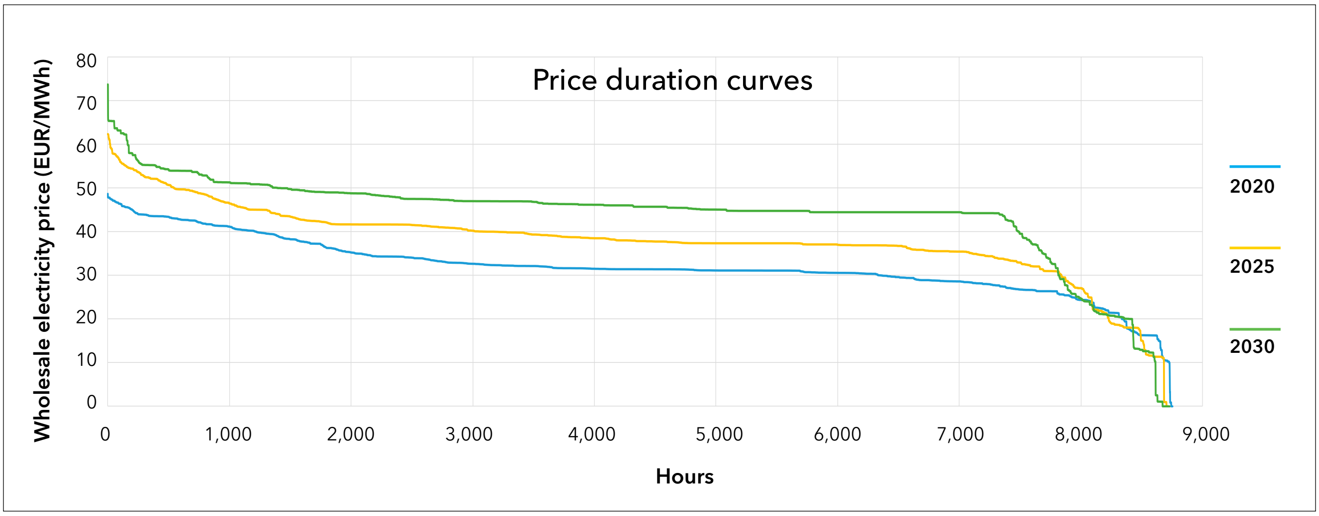


Figure 12 - Electricity price duration curves for 2020, 2025 and 2030

Fuel costs

While the current price spread between electricity and natural gas does not favor power-to-heat, price evolutions, caused by e.g. additional renewable generation, could have a favorable effect that could lead to a positive business case in the future without interference through financing or regulatory change. It is therefore vital to take into account future price developments when calculating the business case. In order to estimate fuel costs, price predictions from the Nationale Energieverkenning (NEV) 2017 were used [15]. Three unit prices were utilized for the calculation of the business case.

Electricity price

The NEV 2017 provides price predictions for the average wholesale electricity prices in 2020 and 2030. In order to create yearly price averages for each year of the business case, interpolation was used between the two points of reference. The same growth rate was also used for back casting prices to 2018 – the starting point for the business case.

As the NEV only contains average wholesale prices, which are insufficient for the calculation of the business case of a hybrid system, price volatility had to be introduced. This was done by utilizing price profiles from DNV GL's own power price forecasting service for 2020 and 2030, and scaling the results to match the average NEV wholesale price. The results are visualized in the price duration curves in figure 12. As can be seen in figure 12, electricity prices up to 2030 show an increase in both average price level and volatility. This price volatility is mainly caused by an increasing penetration of renewables, and leads to an increased number of hours with relatively low prices (signified by the sharper and earlier drop-off in the 2030 curve) when there is significant wind production. Similarly, a sharper price increase can be noted, caused by periods with a lack of wind. Average price increases are mainly the result of the phase-out of cheap coal fired power plants. Fuel costs for the hybrid boiler were calculated by comparing the electricity price to the gas price (including CO_2 costs). For the market optimization scenario, the operating regim was based on the most favorable price on an hourly basis. Based on the NEV price dynamics, this amounts to circa 300 hours in 2018 and builds to 1,200 hours in 2030.

For the wind integration and renewable integration scenarios the cheapest hours were selected, as it was assumed that production of offshore wind would lead to lower market prices.

Gas price

Average wholesale gas prices for 2020 and 2030 were used from the NEV 2017. As these prices are in €ct/m^3, conversion into €/MWh was necessary for price comparison. This was done using a factor of 31.65 MJ/m^3. In order to obtain yearly prices for the entire business case, interpolation was used. Gas prices were assumed to remain constant throughout the year, as price volatility is limited in comparison to volatility in electricity prices.

Energy taxes

Energy tax calculations were based on the Netherlands Tax and Customs Administration (Belastingdienst) 2018 cost tables for consumers >10,000 kWh and <17,000 m^3. Costs for the Opslag Duurzame Energie (ODE), which funds the SDE+ subsidy scheme, were included. The taxes values utilized can be found in table 8.

Tax type	Value
Electricity per kWh (>10^6 kWh commercial)	€0.00057
ODE electricity per kWh (>20^6 kWh commercial)	€0.000194
Gas per m^3 (>10^6 m^3 commercial)	€0.01265
ODE gas per m^3 (>10^6 m^3 commercial)	€0.0021

Table 8 - Tax rates for electricity and natural gas use [19]

	Gas boiler	Market optimization	Wind integration	Renewable integration	Baseload
Electricity tax	-	0.03	0.21	0.42	0.82
Natural gas tax	1.80	1.74	1.3	0.88	-

Table 9 - Energy taxes (in MEUR over the system lifetime)

NEV 2017 prices	2020	2030
Electricity price (€/MWh)	32	44
Gas price (€ct/m^3)	17	31
Gas price (€/MWh - converted)	19	35
CO_2 price (€/ton)	7	16
CO_2 price (€/MWh - converted)	1.5	3.2

Table 10 - NEV 2017 inputs

Total energy tax costs for each of the scenarios can be found in table 9.

CO_2 price

When operating the hybrid boiler on natural gas, CO_2 is emitted by the system. It is therefore necessary for the emitter to hand over an equal amount of CO_2 emission rights. ETS CO_2 prices per MWh_{th} produced using the gas fired system were therefore calculated based on the NEV 2017 expected CO_2 market prices in 2020 and 2030. As these prices are in €/ton CO_2 emitted, conversion into €/MWh was necessary. This was done using a factor of 0.203 ton CO_2 emitted/MWh. A full overview of NEV prices used as input for the business case can be found in table 10.

Calculated fuel costs

The data on commodity prices, CO_2 costs and energy taxes has been combined in a calculation of the fuel cost over the 12-year expected lifetime of the system. The combined costs can be found in table 11. Due to electricity prices remaining unfavourable in comparison to gas prices, the amount of direct savings that can be obtained by switching between fuel types is limited, even in the Market Optimization scenario. The maximum savings that can be obtained is 0.9 MEUR. As the price curve is relatively flat, beside the 1,000 most cheapest and 1,000 most expensive hours, price increases are relatively limited when increasing the number of electrically operated hours. Due to reduced CO_2 costs and energy tax savings, the renewable integration has lower costs than the wind integration scenario, and is close to the gas boiler, despite more electrically operated hours. Differences between the scenarios are limited however, with the exception of the baseload boiler. Due to the size of the price gap for the most expensive hours, the baseload boiler incurs significant additional costs of around 6.5 MEUR.

	Gas boiler	Market optimization	Wind integration	Renewable integration	Baseload
Gas costs	- 29.3	- 26.8	- 23.4	- 14.2	-
Electricity costs	-	- 1.9	- 7.5	- 17.3	- 39.0
CO_2 costs	- 2.2	- 2.0	- 1.7	- 1.1	-
Energy tax	- 1.8	- 1.7	- 1.5	- 1.3	- 0.8
Fuel costs	**- 33.3**	**- 32.4**	**- 34.1**	**- 33.9**	**- 39.8**

Table 11 - Total fuel costs (in MEUR over the system lifetime)

	Gas boiler	Market optimization	Wind integration	Renewable integration	Baseload
CAPEX	-	- 3.1	- 3.1	- 3.1	- 3.1
OPEX	- 0.9	- 5.9	-5.9	- 5.9	-5.9
Fuel costs	- 34.5	- 32.4	- 34.1	- 33.9	- 39.8
NPV (MEUR)	**- 33.2**	**- 41.4**	**- 43.1**	**- 42.9**	**- 48.8**
Cost gap (MEUR)		***8.2***	***9.9***	***9.7***	***15.6***

Table 12 - Comparison of results

Results

Net present value

The CAPEX, OPEX and fuel cost data have been combined to make an overall comparison of the cost gap between a gas fired boiler and more sustainable alternatives. The full results with regard to the Net Present Value (NPV), as well as a comparison of ton CO_2 saved and EUR/ton CO_2 saved can be found in table 12.

Based on the expected development in market dynamics, none of the operating regimes of the hybrid boiler will be economically viable. While fuel savings can be obtained in the Market optimization, Wind integration and Renewable integration scenarios, these do not outweigh the additional costs. As overall costs for these three scenarios are similar, the higher CO_2 emissions savings make Renewable integration the most cost effective regime for increasing sustainability.

When looking at the overall cost distribution in figure 13, a number of conclusions can be drawn:

- The costs allocated to the transport tariff is constant in all scenarios, regardless of the number of hours operated electrically. In case of the Market optimization scenario, the transport tariff costs are more than twice the cost of electricity, and therefore represent a significant barrier for the business case.
- In the Market optimization scenario, the overall costs for electricity are minor. This is an indication that market prices significantly favour natural gas over electricity. Not only does this make it unlikely that the hybrid boiler will become economically viable over time, it also shows that the amount of CO_2 savings will be very limited if left to the market.
- All cases are dominated by commodity costs, which represent about 65-70% of total costs. The more electricity is used, the higher the total cost gap becomes. In order to reduce the amount of natural gas used, it is therefore vital that the price gap with electricity remains limited.

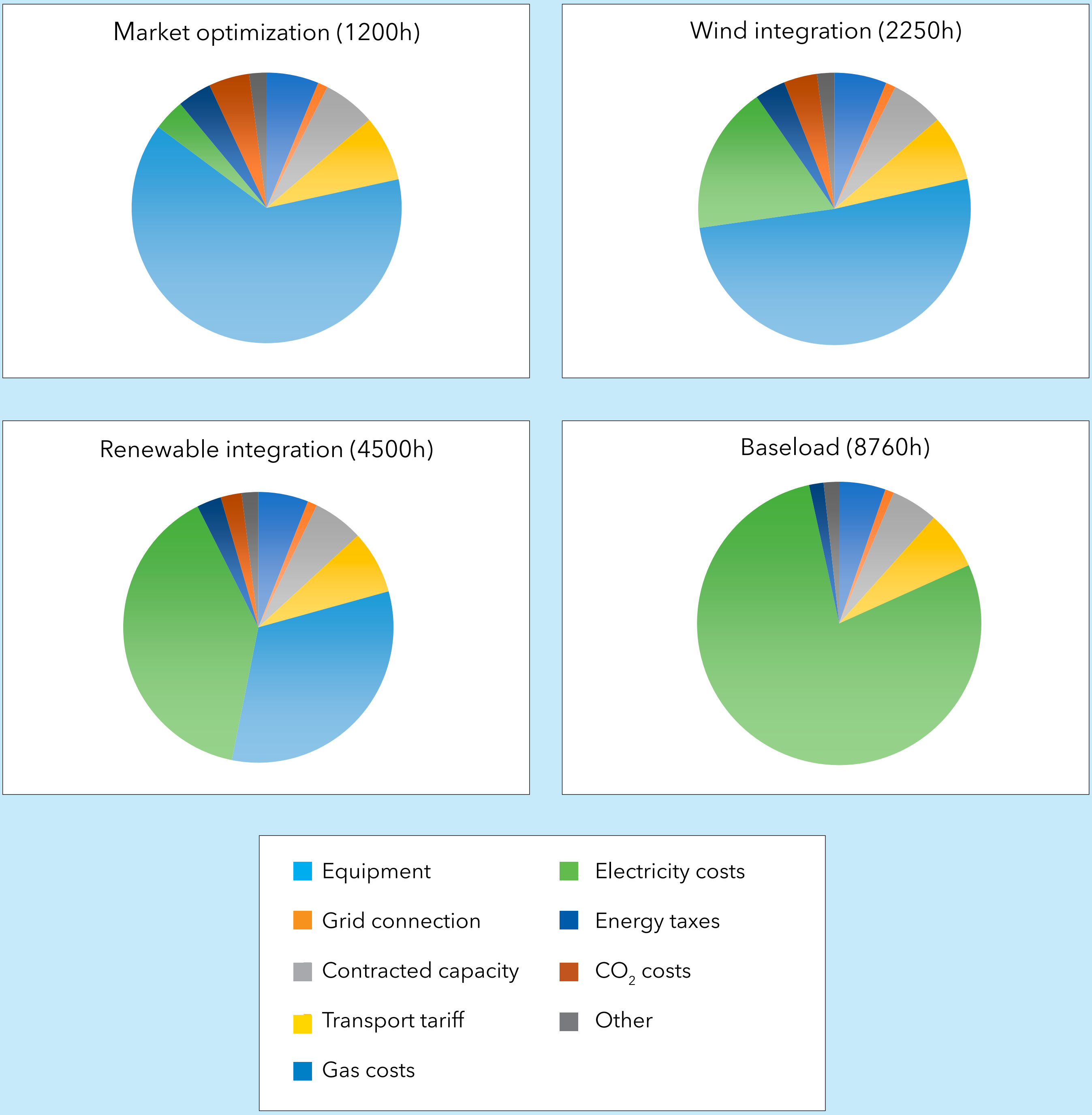


Figure 13 - Cost distribution of the hybrid boiler scenarios

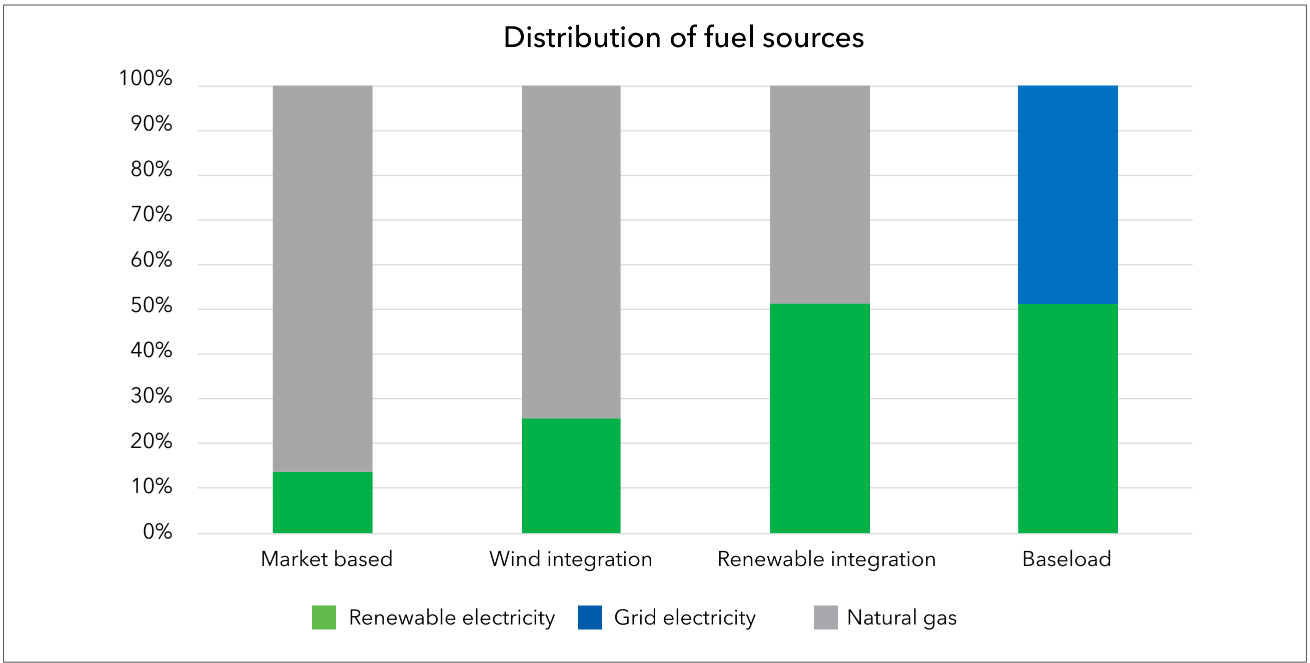


Figure 14 - Distribution of fuel source per scenario

CO_2 emission savings

By combining P2H demand with offshore wind production, CO_2 emission savings can be realized. The amount of savings is dependent on the technology used and the operating regime. For P2H operation, three potential sources of fuel can be used:

- Renewable electricity: limited to 4,500 hours annually, 0 ton/MWh
- Fossil electricity: for electrical operation >4,500 hours, 0.305 ton CO_2/MWh[4]
- Natural gas: hybrid boiler alternative fuel source, 0.203 ton CO_2/MWh[5]

The distribution of fuel sources per scenario are outlined in figure 14. Based on this distribution, the potential CO_2 savings can be found in table 13. Especially for the baseload scenario, please note that this concerns CO_2 savings for the energy system as a whole, and not for the individual consumer, since the grid electricity was generated with a considerable CO_2 emission.

As can be seen, the CO_2 savings potential increases significantly when increasing the hours operated electrically on offshore wind production. However, after the threshold of 4,500 hours of renewable production is reached and electricity from the grid is utilized instead of natural gas, overall CO_2 savings decrease as emissions from the current grid mix are higher than those of burning natural gas. Until the amount of renewables in the grid mix can be increased, running in baseload is not advisable from a sustainability perspective.
When combined with the previously calculated cost gap, the cost of emission savings in €/ton CO_2 saved can be calculated for each of the operating regimes.

	Market optimization	Wind integration	Renewable integration	Baseload
CO_2 savings	32.2	82.5	164.4	86.2

Table 13 - CO_2 emissions savings (in kton over the system lifetime)

	Market optimization	Wind integration	Renewable integration	Baseload
Cost gap (MEUR)	8.2	9.9	9.7	15.6
CO_2 savings (kton)	32.2	82.5	164.4	86.2
€/ton CO_2 saved	**- € 254**	**- € 120**	**- € 59**	**- € 181**

Table 14 - Calculation of cost of emission savings in €/ton CO_2 saved

[4] Based on total generation and emissions in the Netherlands in DNV GL PLEXOS simulations for 2020
[5] Calculated per MWh based on 56.5 ton CO2/TJ [18]

	Market optimization	Wind integration	Renewable integration	Baseload
Economics	++	+	+/-	--
Grid support	+	++	++	
Sustainability	--	-	++	

Table15 - Comparison of scenarious along optimization dimensions

Optimal operating regime

As P2H is not economically viable under current and expected market conditions, an additional instrument is necessary to help close the cost gap. Before such an instrument can be proposed, it is necessary to determine what the purpose of the instrument should be, and what cost component it should address (CAPEX, OPEX or both). For this it is necessary to determine the ideal operating regime for the hybrid boiler from a system perspective. As noted previously, the operating regime can be optimized based on three dimensions:

- economics
- grid support
- sustainability

Based on these three, renewable integration has been determined to be the optimal. The NPV is only 5% higher than in the market optimization scenario, and it is the most cost optimal with regards to €/ton CO_2 saved due to its high CO_2 emissions reduction. All scenarios apart from the baseload scenario have the potential of providing grid support, while avoiding putting added strain on the grid during low offshore wind production hours, through their flexibility in operation. Only the market optimization scenario may not have enough electrically operated hours to reduce all peaks in wind production. It should be noted that the sustainability level of the baseload boiler could increase significantly in the future, when additional renewables are added to the grid mix.

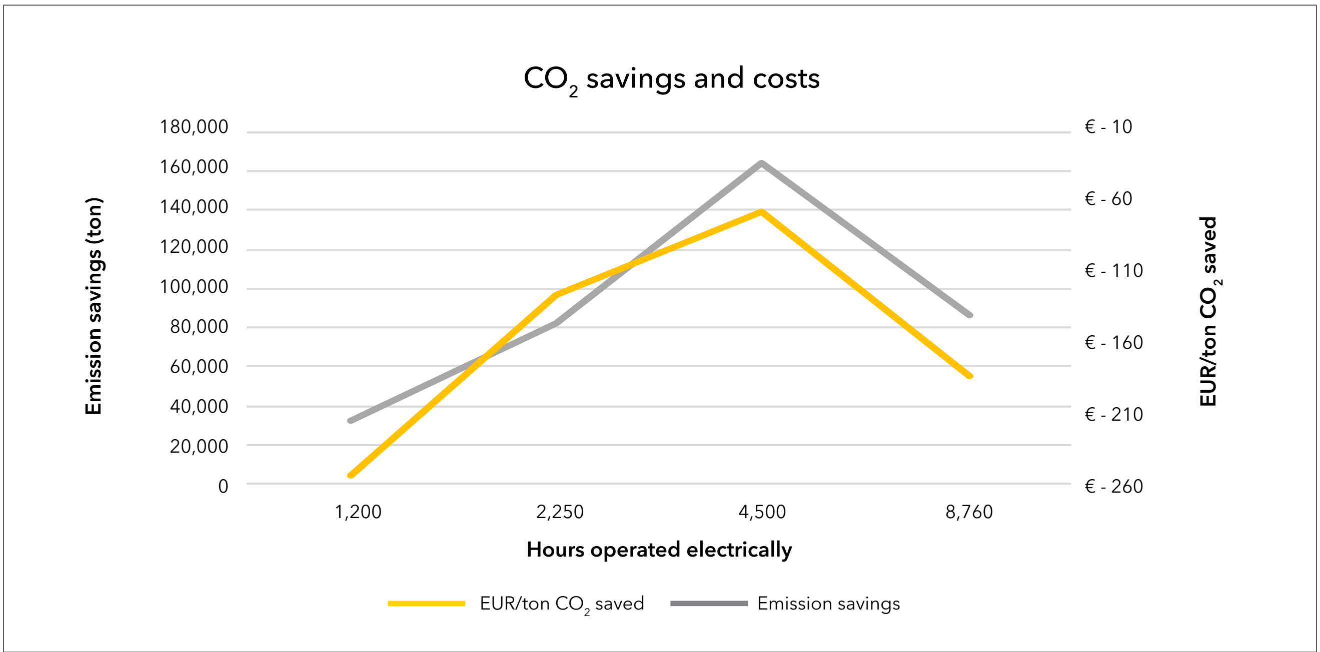


Figure 15 - Overview of emission savings and emission savings costs for the different operating scenarios

Sensitivity

In order to determine what the instrument to close the cost gap should look like, a sensitivity analysis was performed. The main results of this analysis are:

- A combination of incentives is necessary to close the cost gap.
- Due to the hybrid boiler operating using natural gas and electricity at about a 50/50 ratio, the cost gap can't be closed by shifting costs from electricity to natural gas. As a result, additional funds are required.
- Increasing the CO_2 price favours baseload P2H, while being less sustainable than the renewable integration scenario. Switching from natural gas to electricity without increasing sustainability in the generation mix is only an administrative solution that does not consider impact on the system.
- A reduction in gas prices reduces the hybrid boiler NPV, but favours the gas fired alternative more. As a result, a decreasing gas price would lead to an increased cost gap. As the NEV assumes a relatively high growth in gas prices, a greater cost gap than calculated in this chapter could become a reality.

Assumptions

This analysis was performed in two dimensions:

- Net present value: determining under what condition a positive business case can be obtained
- €/ton CO_2 saved: a measure of the price-competitiveness of the technology in comparison to other sustainability measures

To determine price sensitivity, a low scenario and high scenario were used. The low scenario includes price reductions or low values in comparison to the high scenario, regardless of whether this is expected to have a positive effect on the end result.

The sensitivity analysis includes all components of CAPEX and OPEX outlined in the paragraphs 'Parameters and assumptions' and 'Results' on pages 34-40. Additionally, variations of price volatility (for the hybrid system) were added. In most cases, price increases and decreases of 25% were assumed as input.
Some notable exceptions and assumptions:

- The grid connection cost goes up to 300%, due to the high potential for variability and the choice to take an estimate on the low end of the potential spectrum.
- The non-transport tariff consists of a combination of the connection fee, supply and metering fee and contracted power as these are independent of utilization of the connection.
- Transport and non-transport tariffs can potentially go down to 0 in order to investigate the impact of potential exemptions through e.g. flexibility market productions or complete market redesign.
- The CO_2 price estimation in the NEV 2017 is relatively low compared to prices in recent discussions surrounding the Climate Agreement (which go all the way up to €43/ton CO_2 for power plants). As a result, price increases of +100% and +200% compared to the 2020 and 2030 prices were assumed for the low and high scenario respectively.

Sensitivity component	Low scenario	High scenario
Equipment & engineering	-25%	+25%
Grid connection	-25%	+300%
Fixed & variable O&M	-25%	+25%
Transport tariff	-100%	+25%
Non-transport tariffs	-100%	+25%
Electricity price	-25%	+25%
Electricity price volatility (hybrid	-25%	+25%
only)	-25%	+25%
Gas price	-25% electricity, +25% gas	+25% electricity, -25% gas
Energy taxe	+100%	+200%
CO_2 price	-25%	+25%

Table 16 - Sensitivity analysis components and scenarios

- Electricity price increases and decreases were simulated using scaling of individual price points, which has a minor secondary effect on price volatility. Price volatility was simulated using increased stochastic variations around the mean, while keeping the average price constant.
- In the tornado diagrams, components are ranked by total impact of both scenarios combined, regardless of whether it is positive for the business case.
- Discounting factor and lifetime were also investigated with regard to sensitivity, but did not have a significant impact on the end result.

Results

From the tornado diagram in figure 16 it can be concluded that no single instrument is sufficient to reach cost parity with the gas boiler reference case with an NPV of 35.4. As such, the instrument should consist of a combination of incentives.

The most impactful cost components are commodity prices for electricity, gas and CO_2. However, due to the dual fuel nature of the hybrid boiler, it responds positively to cost reductions and negatively to cost increases. Therefore, closing the cost gap between electricity and gas by shifting cost from one fuel to the other is not effective. This implies that a one-sided decrease in electricity prices, or a subsidy that achieves an equivalent outcome, is necessary. In a similar vain, an increase in CO_2 prices will lead to significant cost increases for a hybrid system that is optimized for supporting the grid and CO_2 reductions, instead of optimized based on market prices.

The second most impactful component are the transport and non-transport grid tariffs. While significant reductions to or redesign of the non-transport grid tariffs is unlikely, it provides a strong argument for transport tariff redesign given that the system is operated to support the system and reduce costs, rather than increase costs.

A subsidy on investment in grid connection cost is relatively unimpactful on the NPV, given the assumptions made in this report. However, as grid connection cost can vary significantly from case to case, it is vital that these costs remain manageable to prevent them from becoming a major barrier for investment. Similarly, the impact of the equipment costs can also form a significant burden for investment.

Lastly, it is important to mention the shift in energy taxation, which has limited impact. While energy taxes are a significant portion of the energy costs for household consumers, the relative cost for large consumers is marginal. Additionally, the hybrid boiler will consume electricity and gas in about a 50/50 ratio. Therefore, due to the fact that relatively energy taxes on natural gas are higher than those on electricity, a shift in tax from electricity to natural gas will actually lead to an overall cost increase.

The €/ton CO_2 saved parameter is important to consider, as it takes into account cost developments to the gas boiler alternative as well.

The main point to note is that an increase in CO_2 price is the most beneficial for the hybrid boiler in €/ton CO_2 saved, and even leads to a positive return on investment. This counteracts the earlier insight, which showed an overall increase in NPV. The reason for this is that the gas boiler is impacted even more significantly by an increase in CO_2 pricing. Under current CO_2 accounting practices, emissions from the consumption of natural gas are allocated to the consumer, but emissions from the consumption of electricity are allocated to the producer. As a result, an increase in CO_2 price is most beneficial to a boiler running in baseload, as it will not get CO_2 allocated to it.

So paradoxically, increasing CO_2 prices would benefit the baseload boiler over the hybrid boiler running at 4,500 hours annually, although the latter has been shown in the paragraph about CO_2 emission savings on page 40 to lead to more CO_2 reductions.
As such, it should be noted that forcing a switch from natural gas use to electricity that is mainly generated using the same natural gas is only an administrative solution that incentivises the consumer to maximise the usage of electricity, which is not necessarily beneficial for the system.

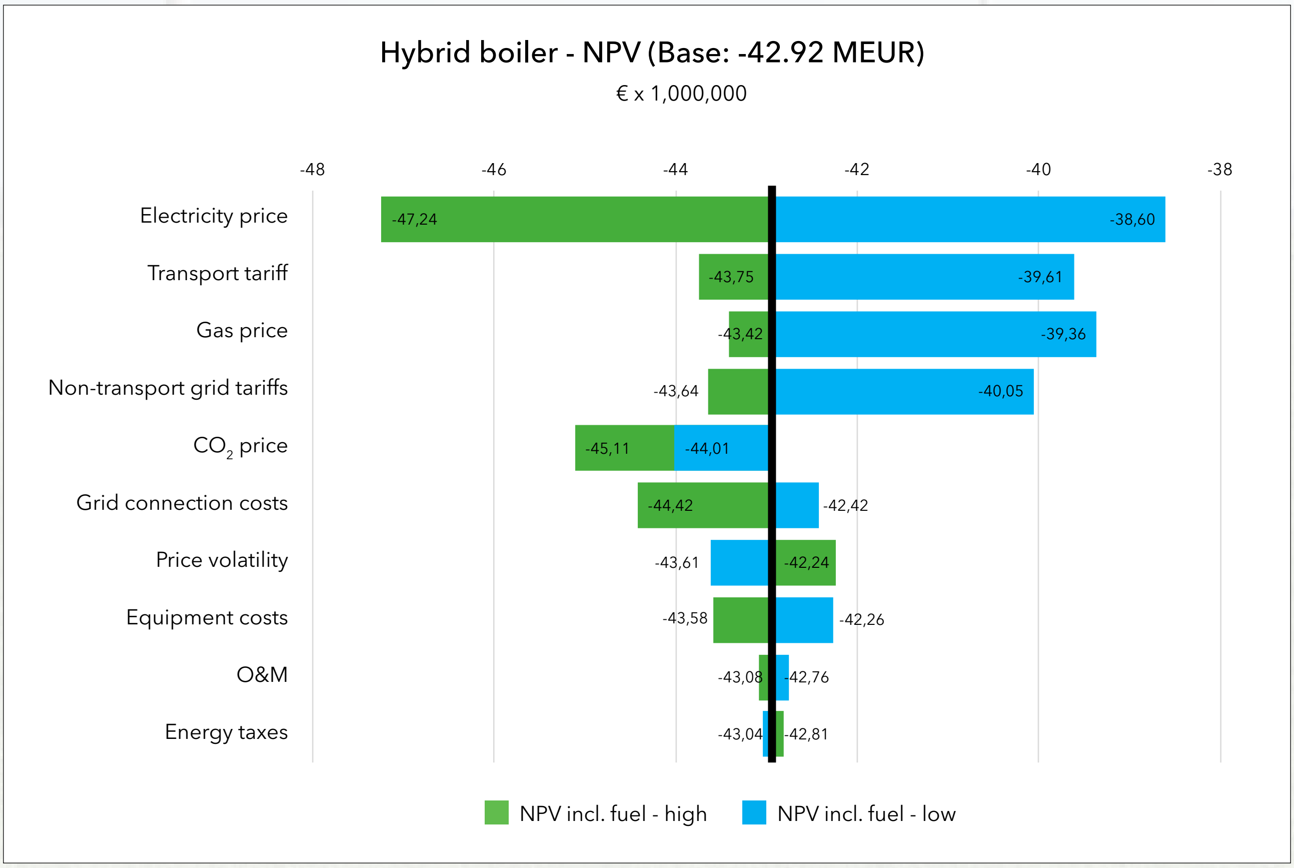


Figure 16 - NPV sensitivity

Variations in gas price also show an opposite effect with regard to €/ton CO_2 saved in comparison to the NPV sensitivity. While a low gas price is beneficial for the hybrid boiler, it benefits the alternative even more. As the NEV scenarios utilized in the business case assume a strong growth in wholesale gas prices, gas price development can have a significant impact on the size of the cost gap that will have to be closed between P2H and the gas boiler.

In a similar vain, the volatility in electricity prices can have a significant impact on the business case. As this is not just dependent on the generation mix, but also on developments in consumption, technology, market and even weather and climate, price volatility is hard to predict and influence and will therefore not be included in any recommendations regarding an instrument to close the price gap.

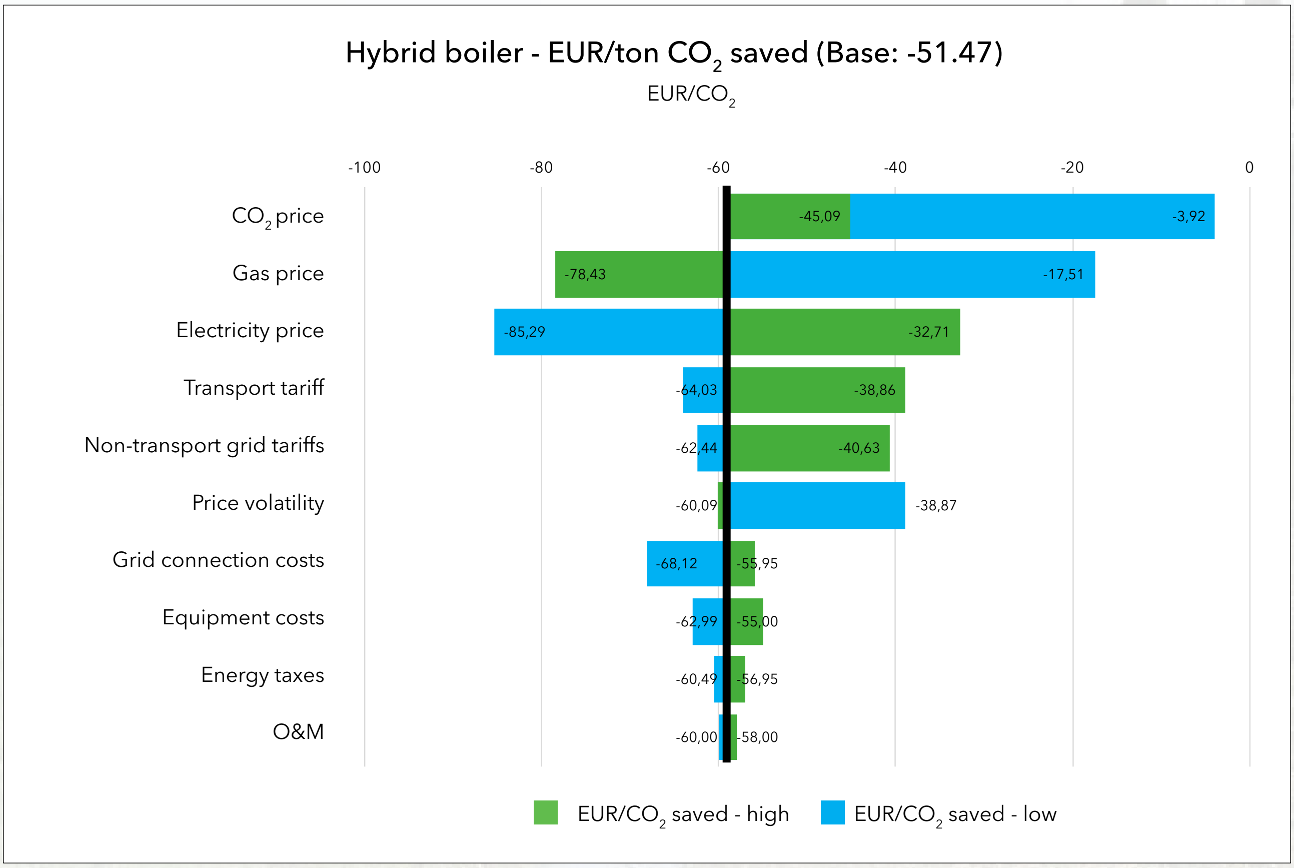


Figure 17 - EUR/ton CO_2 saved sensitivity

CLOSING THE COST GAP

In the previous chapter, the size of the cost gap and the main components responsible for causing the cost gap have been identified, such as commodity prices and network tariffs. This chapter discusses potential alternatives to potentially close the gap. The focus is on alternative measures with substantial impact on the business cases (following the sensitivity analysis). Therefore, the next sections discuss measures in relation to network tariffs, distinguishing between the contracted capacity and the kWmax component, and measures in relation to commodity prices (electricity, gas and CO_2).
Recommendations for change implementation are highlighted in the next chapter.

CAPEX

As shown in the previous chapter, CAPEX makes up a significant portion of total costs and is therefore a prime target for subsidization. This subsidization can focus on either equipment costs or the grid connection.

Equipment costs, and especially EPC costs, make up the largest portion of CAPEX. This can form a major hurdle for investors. Reducing this barrier through subsidization could speed up the transition to P2H.

Under the assumptions used, the grid connection costs are limited. However, these can increase strongly up to multiple MEUR, depending on the location. This could lead to a serious investment barrier for consumers that do not happen to be located near an HV substation. While it is possible to subsidize the full grid connection, it is especially necessary that costs for investors remain limited by focusing the subsidy on the variable (distance dependent) part of costs.

As CAPEX subsidies are provided beforehand, and do not work based on performance indicators, it may be wise to put in place certain preconditions for recipients of the subsidy (e.g. minimum number of hours to be operated electrically).

OPEX

Regarding OPEX, both the transport and non-transport grid tariffs have a significant impact on the business case. However, it is much more logical to target the transport tariff for closing the cost gap as the non-transport grid tariffs are reflective of actual cost while the transport tariff is not. For OPEX it is not necessary to implement subsidies. Redesign of the current grid tariff would have the same effect, without leading to additional costs.

Electricity network tariff redesign

Electricity consumers pay for the use of the electricity grid. Besides the transport-independent tariff (fixed or standing tariff) which are equal for each tariff category, the transport-dependent tariff covers the costs of electricity transmission and distribution (construction and maintenance of grids, depreciation, maintaining voltage levels, and reactive power management).

For transport-dependent tariffs (variable tariffs), the contracted capacity determines the classification of each consumer in a tariff group and the voltage level at which the consumer is connected. For these tariffs, we assume that the industries and P2H options considered in this report are classified as 'HS/MS', i.e. High Voltage/ Intermediate Voltage with a yearly contracted capacity above 1500 kW.

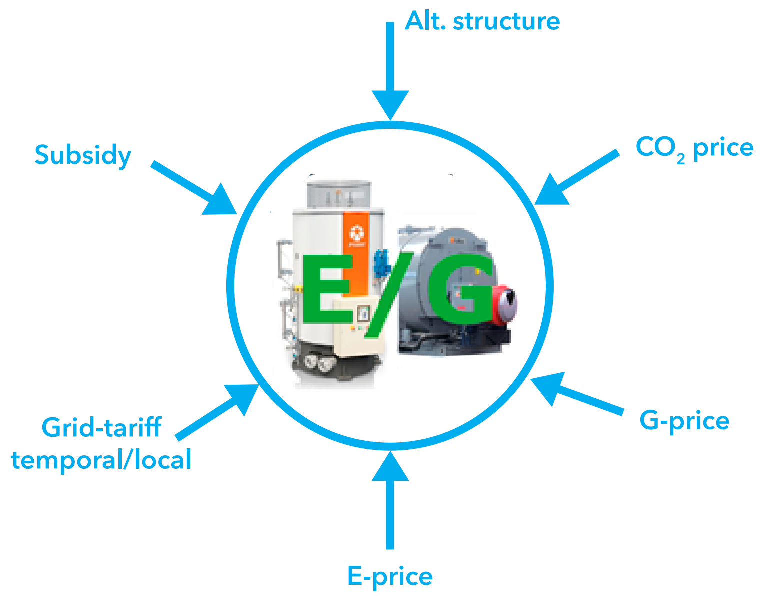


Figure 18 - Factors determining the business case for the hybrid boiler and electrification in industry

For these categories, tariffs are charged based on kiloWatt (kW), distinguishing between:

- kW contract: a tariff in €/kW/year for contracted capacity (expected maximum capacity during the year)
- kW max: a tariff in €/kW/month (or per week) for the actual peak capacity used (15 minutes basis) per month (or week)

For the grid operator each of these tariffs covers 50% of the transport-dependent costs.

Only when an individual network user requires substantial low operating times (<600 hours per year), and when connected to intermediate voltage levels or higher, special tariffs apply because of limited use of the electricity network. With operating times higher than 5,700 hours and using more than 50 GWh per year, a discount on transport tariffs may apply because of the contribution to stability of the grid.

Various parties have indicated that this tariff structure of kW contract and kW max is detrimental for the business case of large industrial end-users of electricity, especially when operating below 5,700 hours annually. This is confirmed by the calculations of the business cases in the results section on page 38.

A switch to P2H would normally mean that the connection capacity needs to increase, and thus that the transport tariff determined by kW contract and kW max increases. Even if operating hours are low (but still larger than 600 hours), e.g. in the case of a hybrid boiler, the higher tariffs apply.

Moreover, in this case, the industrial user is paying the same as an industrial user with constant high capacity use (high operating hours).

Considering the above, alternative tariff structures that would better represent the allocation of network costs (according to cost-by-cause principle), and make P2H and flexibility options more attractive, are discussed.

Locational network tariffs allow to account for differences in grid use and related costs (congestion or not) between regions. The motivation to apply locational pricing relates to designing a regime that properly accounts for locational variations in network usage. The current Dutch network tariffs are more or less uniform, only differentiated by regional network operator and voltage level. Further differentiation based on locally incurred grid costs would allow for tariffs based on grid congestion and grid losses. Locational cost based tariffs are not widely used in practice, because locational charges might lead to substantial differences in the payment of transmission users connected in different areas of the network. For this reason, they might even be occasionally perceived as being inequitable (e.g. existing regional charges in Dutch gas transmission).

Given that the increasing production of wind power from the North Sea has to be transported and further transmitted into the country, it may help to prevent congestion when industrial clusters (near the coast) are confronted with lower network tariffs.

However, locally increasing the load in lower network levels (e.g. 150 kV), may solve problems in the transport grid (congestion, e.g. due to additional production of offshore wind power), but at the same time may aggrevate already existing congestion in the lower grid.

Time-of-use tariffs are often designed to vary with the time of day, week and year, generally with the aim of reflecting the variation in the costs of providing the service and/or, particularly in the infrastructure pricing, accounting for users' consumption behaviour. As the overall capacity and, hence their cost, are dictated by the peak loading to which they are designed, higher proportion of costs are allocated to parties using the system during these periods.

The application of time-of-use tariffs leads to differences in payments for transmission charges for users who consume the same energy, but at different time periods. Users off-taking energy during peak demand periods will need to pay higher effective charges than users consuming electricity in off-peak periods. Time-of-use tariffs are generally used to promote a more even network load, which may delay or prevent network investment. However, as the infeed of offshore wind does not occur at predictable peaks, the applicability of time-of-use tariffs is limited.

Traffic light tariffs are a variation of time-of-use prices. Using information on the system or a local system signal that larger electricity consumers can use to make an informed decision about whether or not to offtake electricity. E.g. if the signal from the grid is green there is no congestion and using the grid in the specified location and time is relatively cheap.

Utilization based tariffs are meant to be a more fair representation of costs resulting from grid losses. As a higher cable utilization increases resistance and therefore losses (which have to be compensated by the TSO and DSO), low utilization due to a low number of operating hours or low cable loading will decrease losses incurred. Instead of paying for the maximum demand at a given point in time (kW max), an utilization based tariff would make the consumer pay for his part in actual losses. Utilization can be done based on average percentage of cable loading, or losses can be calculated based on the total volume that passes through the cable (Norwegian model). However, utilization based tariffs are only reflective of costs resulting from grid losses and not of other costs. A purely utilization based tariff would therefore still not be reflective of cost incurrence, and not suited as the basis for a new tariff structure.

Producer tariff. Assuming certain network costs for the grid operator, introducing variable, transport-dependent tariffs to producers as well (e.g. a kW contract tariff for feed-in of electricity by producers) would at the same time mean the that the kW related tariffs for consumers can come down. With the growing impact of (renewable) energy production on congestion and network costs it can be argued that 'socialization' of transport-related variable cost would be fair. Moreover, it would provide incentives to electricity producers when considering the transmission costs resulting from the location decisions.

Commodity prices

Important drivers in the business cases are the market prices for gas, electricity and CO_2. Given the relatively low gas and CO_2 price, as well as the high electricity price, the gas boiler reference case remains the preferred option. I.e. higher gas prices, lower electricity prices and higher CO_2 prices would incentivise a switch to P2H.

These commodity prices are however the result of market forces and in our open and liquid market difficult to 'manipulate'. Taxes and subsidies can be used to compensate for incurred costs and/or provide steering for desired consumer behaviour, but this requires careful consideration to avoid unwanted side-effects and inefficiencies in the market.

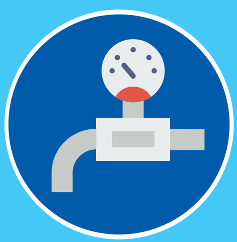
The Dutch SDE+ regulation is an example of producer subsidies, aiming to bring down costs of renewable production. Consumer subsidies, steering the prices paid by energy users downwards, can include two components: a pre-tax subsidy and a tax subsidy. As an example of the latter, the Dutch energy tax ('Energiebelasting') on the use of both electricity and gas can be used to change the relative prices paid by consumers. The current tendency in the Netherlands, for example in the discussions on the new Climate Agreement, is indeed to shift the energy tax from electricity to gas use. Linking the energy tax to the CO_2 emissions of energy sources could also be considered. Note that in the current energy tax system, special refunds may apply, e.g. if you use more than 10 million kWh and have concluded a long-term agreement with the government to improve energy efficiency.

ELECTRICITY PRICE

According to the NEV 2017, the electricity price will continue to increase up to 2030, thus not helping the business case for (baseload) P2H technologies.

Besides the level of price, price volatility has an impact as well. Higher price volatility may be expected with rising levels of wind and solar power, which would be supportive for the implementation of the flexible hybrid boiler. On the other hand, further progressing market coupling and development of the internal energy market may lead to less price volatility.

GAS PRICE



The phasing-out of natural gas is an important discussion nowadays in the Netherlands. Various ideas and measures to stimulate the substituting of the use of gas by alternative energy sources are being considered. For example, in the built environment a SDE+ like subsidy tender may be introduced to bring down costs of making houses or neighbourhoods more sustainable. A similar measure could also help industry to switch to P2H (aiming to reduce costs). Since large industrial L-gas users are also requested by the Ministry of Economic Affairs and Climate to switch away from the use of (L-) gas. However, the effect of such a development on the commodity price of gas is expected to be limited.

CO_2 PRICE

Clearly, the potential for CO_2 reduction is larger for the baseload electric boiler than for the flexible hybrid boiler. Therefore, also the effect of the CO_2 price is larger in case of the electric boiler and thus in the longer term.

The discussion on the 'right' CO_2 price is much wider than just related to P2H investments. It is generally regarded that CO_2 pricing is either not internalised in (investment) decisions (i.e. the price and merits of emission reduction is not regarded at all) or it is too low. Further emission reduction obligations or carbon taxation would drive the CO_2 price up, advocating decarbonizing projects at the expense of fossil-fuel based project. However, in order to retain international competitiveness of Dutch industry, it is paramount that these developments take place on a European level and not solely on a national level.

RECOMMENDATIONS

As was shown in the cost/benefit-analysis performed in the chapter on cost assessment of P2H in industry on page 32, no single measure is sufficient to close the cost gap between P2H and the gas fired alternative. As such, a combination of measures is necessary. These are to be combined in an instrument that adheres to specific conditions. For selecting measures to be included in the instrument, the following criteria were considered:

- Robustness in terms of timing: will or can the measures have a short term (e.g. up to 5 years from now) or long term impact on P2H
- Effectiveness in stimulating P2H: measures are effective if they have substantial impact on the business cases
- Undesirable side effects

This recommendation section will start with sketching a recommended transition pathway, before going into on what measures should be implemented at what point in the transition pathway. The section will conclude with suggestions on the instrument, as well as minimal conditions that the instrument should adhere to, as well as necessary precondtions.

Transition pathway

To realize the potential for P2H in industry, investments will have to be made. However, what investments are made, and when, is dependent on both the business case and potential obstacles or barriers. Due to unfavourable commodity prices and previous investments into gas boiler systems, it is unlikely that industry will replace its gas boilers before they are end-of-life. Therefore, a transition that starts by adding electric boilers or retrofitting existing boilers with an electrical heating element to create hybrid systems is the alternative with the lowest barrier. These hybrid boilers should at minimum be operated in order to facilitate the integration of offshore wind, and preferably aim to maximize CO_2 emission reductions. When the gas boilers are end-of-life, the electrical boiler could remain as baseload electrification. Once the initial electrical boiler is end-of-life, development of high temperature heat pumps may have progressed far enough to be cost effective and energy-efficient replacements. As industrial turnarounds typically have up to six years in between, and require up to four years in advance to plan, implementation of instruments is necessary before 2020 to allow sufficient time for the industry to adopt P2H systems.

Stimulating measures

In order to facilitate the initial investment, it is necessary to remove or reduce the initial investment barrier. This can be done by targeting investment costs in installation of equipment and rolling out the necessary grid infrastructure on the industrial site. Secondly, the price risk needs to be reduced to ensure that hybrid systems can be operated electrically without incurring significant added costs per MWh compared to the gas fired alternative. When considering the distribution of marginal costs in figure 20, it is apparent that for a low number of electrically operated hours, which is the minimum requirement to reduce congestion in the transport grid, costs are highly dependent on network tariffs. To facilitate the integration of offshore wind, it is

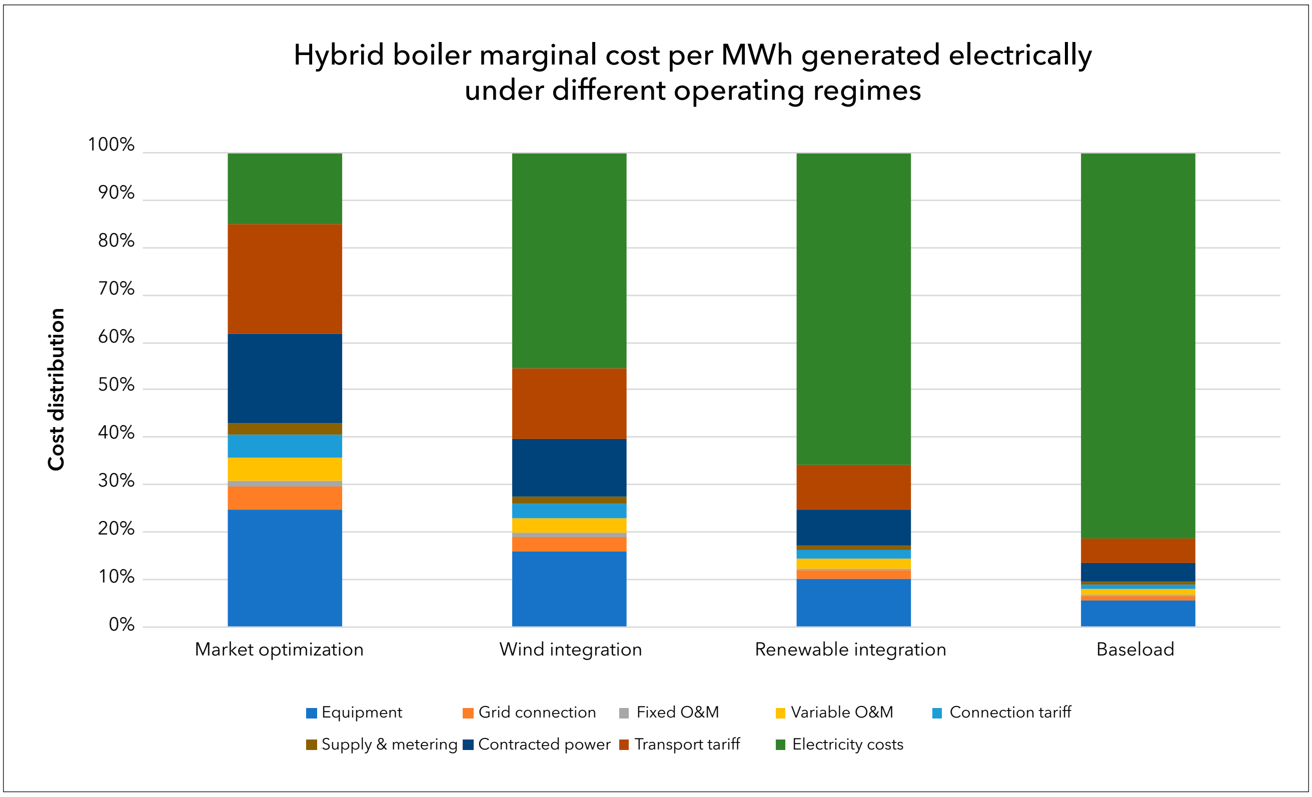


Figure 19 - Distribution of marginal costs

therefore recommended to redesign the tariff structure. Utilization of a transport tariff that is more reflective of actual cost, by taking into account network load, would be preferable. For example, a traffic light or time-of-use model would be suitable, and has the most similarities with the existing tariff structure.

While the facilitation of offshore wind will be beneficial for the system, the main purpose of P2H should remain maximizing reductions of CO_2 emissions by increasing the number of hours operated electrically. As figure 20 shows, an increase in electrically operated hours will lead to the cost of electricity becoming the most dominant marginal cost component by a significant margin. As a result, in order to stimulate CO_2 reduction it is necessary to subsidize commodity cost. This can be realized through a financial incentive or subsidy aimed at reducing the cost of electricity consumption.

As noted, consuming electricity without the emissions associated with electricity production will not necesarily benefit the system. Therefore, to avoid purely administrative solutions for consumers and maximise system emission reductions, such a subsidy should be limited to renewable consumption. This can initially be achieved using the 4,500 hours of offshore wind production, but should eventually expand beyond this level. Until more renewables can be realized in the generation mix, subsidizing the use of non-renewable electricity will actually reduce the amount of CO_2 savings that can be achieved (as was shown in the section on CO_2 emission savings on page 40). Once sufficient renewables are realized, fully phasing out natural gas use in favour of baseload operation of electric boilers should be realized. This could require additional subsidization of consumption, although it is possible that this increased amount of renewables will have sufficiently reduced wholesale electricity prices to operate cost-effectively.

Combining measures into a policy instrument

Regulatory changes and financial incentives should be combined into a policy instrument. While the specifics of this instrument are still the subject of heavy debate, this section aims to provide a number of conditions and prerequisites that are to be taken into account.
The instrument should at least:

Close the cost gap for P2H: To be achieved using a combination of the measures described above.

Solve the chicken-and-egg-problem: System-wide CO_2 savings can only be achieved if additional production of offshore wind is realized that is at least equal to the additional electrical demand created by P2H.
This will lead to a chicken-and-egg problem, where the first mover suffers from the majority of the risk.
The instrument should solve this problem by rewarding the first mover or mitigate the risk. Additionally, it is important that the growth of production and demand are matched in time.

Facilitate a match of P2H demand and offshore wind production: For facilitation of offshore wind production in the transport grid, it is necessary that the demand for P2H is matched in time with the supply of offshore wind. This can be realized either directly or indirectly through the market. Direct coupling can be achieved e.g. through bilateral contracts between industrial consumers and wind farms. Indirect coupling can be realized through e.g. Power Purchase Agreements in combination with real-time Guarantees of Origin (taking into account fair CO_2 allocation) or through the wholesale market, when high wind production leads to low prices. Regardless of the methodology, it is important that there is sufficient guarantee of consumption to ensure future investments in offshore wind.

Fair allocation of CO_2 savings: In the current emission registration, CO_2 emissions from the consumption of natural gas are allocated to the industrial gas consumer, while emissions from electricity production are allocated to the e-producer and not to electricity consumer.
Taken to extremes, this could lead to a situation where industrial consumers are stimulated to consume the maximum amount of electricity in order to reduce their CO_2 emissions, without taking into account the impact on the system.

On the other hand, those who would take into account system impact and for that reason limit their electricity consumption at certain times, would not be rewarded for their behaviour. The instrument should alter this and incorporate fair allocation of CO_2 emissions for the use of non-renewable electricity, and of emission reductions for those that invest in benefiting the system.

This instrument should also take into account a number of necessary preconditions. As previously stated, it is important that the instrument **should be realized before 2020**. Furthermore, it is necessary that the underlying **150 kV grid can support the additional demand** from P2H.

When implemented correctly, the instrument can unlock the full 5 GW in potential for P2H. When the necessary renewable production is realized, operation at the renewable integration scenario can lead to up to 4.5 Mton in CO_2 emission reduction. The total cost for such an instrument, at circa €60 per ton CO_2 saved, is around 3 BEUR over the 12-year lifetime of the boiler system, or around 250 MEUR per year. In order to provide sufficient time for a transition to P2H, this instrument will have to be in place by 2020. Furthermore, it is necessary to start setting up pilot projects as soon as possible to gain practical experience with the alignment of production and demand, and to gain insight into the actual costs and benefits that will help determine the total amount of funds necessary to facilitate a transition to P2H in industry. Once P2H can be fed using 100% renewables, baseload operation can push total CO emission reduction to 8.8 Mton. This level of reduction can bring both industry and the Netherlands closer to achieving their respective climate goals, and take a big step toward a more sustainable society.

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NOTES

SAFER, SMARTER, GREENER

DNV GL - Energy
Utrechtseweg 310-B50
6812 AR Arnhem
The Netherlands
Tel: +31 26 356 9111
Email: contact.energy@dnvgl.com
www.dnvgl.com

Authors
Joost de Wolff, Mats de Ronde, Maroeska Boots

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