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Power-to-ammonia in future North European 100 % renewable power and heat system

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ABSTRACT

Power-to-gas and other chemicals-based storages are often suggested for energy systems with high shares of variable renewable energy. Here we study the North European power and district heat system with alternative long-term storage, the power-to-ammonia (P2A) technology. Assuming fully renewable power and heat sectors and large-scale electrification of road transport, we perform simultaneous optimization of capacity investments and dispatch scheduling of wind, solar, hydro and thermal power, energy storages as well as transmission, focusing on year 2050. We find that P2A has three major roles: it provides renewable feedstock to fertilizer industry and it contributes significantly to system balancing over both time (energy storage) and space (energy transfer). The marginal cost of power-based ammonia production in the studied scenarios varied between 431 and 528 €/t, which is in the range of recent ammonia prices. Costs of P2A plants were dominated by electrolysis. In the power and heat sector, with our cost assumptions, P2A becomes competitive compared to fossil natural gas only if gas price or CO_2 emission price rises above 70 €/MWh or 200 €/tCO_2.

Introduction

The U.N. Intergovernmental Panel on Climate Change has estimated that human activity is responsible for the climate change with greater than 95% probability [1]. EU has set itself a long-term goal of reducing greenhouse gas emissions by 80–95%, when compared to 1990 levels, by 2050. There is thus a great urgency to develop and deploy carbon-neutral energy technologies.

Solar power and wind power have become affordable technologies for energy production but they are hindered by variability, seasonality and uncertainty. Balancing of renewable energy will pose a serious challenge to realizing a fully renewable energy supply. While efficient transmission and demand response can offer a partial solution, a number of mechanical, electrical, thermal, and chemical methods have been developed for storing electrical energy [2,3]. Chemicals-based storage offers the advantage of being able to store large amounts of energy for long periods of time. They also enjoy substantial design flexibility [4], e.g. storage size and power capacity are easy to separate. In many cases, chemicals-based energy storage are not merely storages but also act in a dual role as producers of synthetic fuels or chemicals. Developing synthetic fuels on a global scale is a key enabling element in decarbonizing also other sectors besides the power and district heating sectors.

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Nomenclature

ASU	Air Separation Unit
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
ETS	Emissions Trading System
EV	Electric Vehicle
GDP	Gross Domestic Product
HHV	Higher Heating Value
LHV	Lower Heating Value
OCGT	Open Cycle Gas Turbine
P2A	Power-to-ammonia
PEM	Proton Exchange Membrane
PV	Photovoltaic
STP	Standard Temperature and Pressure
$\eta_{ely,th}$	Electrolyzer efficiency
H	Electrolyzer hydrogen output
H_{max}	Electrolyzer maximum hydrogen output
h	Specific hydrogen output
J_0	Electrolysis nominal current density
P_{ely}	Electrolyzer power input

Presently, water electrolysis is seen as the most feasible technology in power to chemicals conversion [5]. Hydrogen has been long studied as an energy carrier. Cost and technical characteristics of water electrolysis technologies as well as future trends are presented in reviews [6–8], indicating that attractive investment costs and performance are within reach before 2030. However, hydrogen storage is expensive and inconvenient and therefore other chemicals which serve as hydrogen carriers must be considered [4]. At least two alternative routes for stationary chemical hydrogen storage can be defined: carbon and nitrogen chemistries [5]. The former includes the conversion of power via hydrogen into methane, called power to gas (P2G) [9], or into methanol. Both add energy losses compared to pure hydrogen as energy carrier. Still, P2G has the advantage of existing infrastructure for methane transport and storage, compared to hydrogen which requires new challenging infrastructure [10,11].

The second route is to convert hydrogen into nitrogen-based fuels. The simplest such fuel is ammonia (NH_3), hence the term ammonia economy [5]. NH_3 is the second largest synthetic inorganic commodity produced worldwide [12], with 80% of the production used by the fertilizer industry. NH_3 carries the nitrogen component to manufactured nitrogen fertilizers, which currently contribute to feeding around half of the population in the world [13]. NH_3 is also used in the production of nitric acid via the Ostwald process and as a refrigerant. NH_3 is normally produced in the Haber-Bosch process from elemental nitrogen and hydrogen derived mainly from steam-reformed natural gas. Steam reforming of the natural gas has high energy and carbon intensity [14]. EU average ammonia plants consume 35.2 GJ (LHV) natural gas per tonne of NH_3, emitting 1.9–2.1 tonnes of CO_2 per tonne of NH_3 produced [15,16]. If hydrogen is produced by other fossil feedstock or coal gasification the CO_2 emission is substantially higher [17]. Conventional ammonia production alone is responsible for 0.93% of global greenhouse gas emissions [13].

NH_3 produced from renewable hydrogen can reduce greenhouse gas emissions [18,19]: the Haber-Bosch process can also be fed with renewable hydrogen, which according to conceptual studies could be obtained from biomass gasification [20], or via water electrolysis from renewable power like solar [21], wind [22,23], or hydro power [24]. The combined application of water electrolysis and Haber-Bosch process is called power-to-ammonia (P2A) technology. The advantage of nitrogen-based fuels is that nitrogen, abundant in the atmosphere, can be used as feedstock, whereas methanation or methanol production require CO_2. CO_2 may be extracted from point sources if additional purification steps are used to prevent degradation of methanation catalysts. Also separation of CO_2 from the atmosphere has been considered as an alternative, but the energy requirement of CO_2 separation from the atmosphere is an order of magnitude greater than that of nitrogen [5], and it has considerable cost uncertainty as technology is immature.

NH_3 can be combusted in fuel cells [25], reciprocating engines or gas turbines. Although it cannot be easily used in existing Otto cycle engines because its narrow flammability range, NH_3-fired engines have been built for buses already during World War II [26]. NH_3 can be directly combusted in solid oxide fuel cells [26]. Another possibility, which avoids the formation of nitrous oxide in NH_3 combustion, is the decomposition of NH_3 into its elements by catalytic cracking or the sodium-amide process [27]. The produced hydrogen can then be combusted in fuel cells or gas turbines.

NH_3 has a number of clear advantages as synthetic fuel and energy storage. It contains no carbon and therefore its combustion does not produce CO_2. It can be easily as liquid stored in atmospheric pressure by cooling to $-33\,^{\circ}C$ or pressurized at 9 bar in room temperature [27,28]. The cost of storage is low, and can be densely stored for large energy amounts without any significant losses [29]. A typical liquid NH_3 storage tank in the Corn Belt, USA, has a capacity of 30,000 Mt, equal to 190 GWh as H_2 reformed from NH_3, with estimated capital cost of only ~0.1US$/kWh [29]. Large existing infrastructure is in place for the transportation and storage of NH_3. NH_3 is regularly transported in carbon-steel pipelines, rail cars, trucks and ships [29]. Its disadvantage is toxicity, which however, is not a major problem in power generation because there are well-established handling procedures and the fuel's historical safety record is good [12]. NH_3 has a pungent odor which acts as a warning of dangerous level of exposure. In the fertilizer industry, NH_3 produced from renewable hydrogen can reduce greenhouse gas emissions:

NH_3-derived chemicals such as hydrazine (N_2H_4), ammonia borane (NH_3BH_3), ammonia carbonate ($(NH_4)_2CO_3$) and urea ($CO(NH_2)_2$) and can be mentioned as potential NH_3 storage, indirect H_2 storage or alternative fuels [25]. Fuel cells using directly these NH_3 related materials or their solutions have been demonstrated, and safety is not an issue if NH_3 is stored in solids such as $(NH_4)_2CO_3$ or $CO(NH_2)_2$ [25].

The ammonia economy has been studied and reported in the literature from the perspective of process modeling and simulation [30–32], use of ammonia as energy storage in an islanded system [28], value chain analysis of avoiding grid investments and producing renewable NH_3 for fertilizer industry [33]. Also, the optimal scheduling of power-to-ammonia plant in power markets in case the plant acts as price taker, which is the case of a single producer, has been studied [34]. The results concerning the large-scale deployment of power-to-ammonia plants in future energy systems have received much less attention.

In this paper we study the feasibility of the power-to-ammonia concept in the future North European energy system. The analysis concerns the large-scale system, where both power and district heat systems are included. Both the application as energy storage to cover periods of low wind and application in production of fertilizers are considered.

The paper is organized as follows. Section Description of technological processes and assumptions explains the main conversion and storage processes contained in the system with modeling of their cost, efficiency and technological restrictions. Section Simulation model describes the simulation model. Section Results and discussion presents results and discussion and Section Conclusions gives conclusions.

Description of technological processes and assumptions

Power-to-ammonia (P2A) plant

An ammonia plant can be divided into two main subsystems: gas supply and ammonia synthesis systems [30]. In our model three components are distinguished: electrolysis, intermediate hydrogen buffer and ammonia synthesis. Air separation is implicitly included. Ammonia storage, which may or may not be co-located with the plant, is a fourth component.

Electrolysis

Of the different electrolysis technologies proton-exchange membrane (PEM) electrolysis is included in this study because of its flexibility [35]. According to Ref. [36] commercial electrolyzers can reach the efficiency of 50 kWh/kgH_2, which includes power electronics and balance-of-plant equipment. According to Ref. [8] the system efficiency (including auxiliary devices) of PEM electrolysis is currently 56–66 kWh/kgH_2. Bertuolucci et al. [37] anticipate that the specific consumption (input electrical energy per hydrogen output) of PEM electrolysis in 2030 could be 44–53 kWh/kgH_2. Ref. [38] estimates potential efficiency of 45 kWh/kgH_2. Efficiency improvements are limited, because thermodynamic principles limit the maximum efficiency [36].

The above numbers refer to efficiency at full load. Contrary to thermal power plants, electrolysis efficiency decreases as load increases. For example, Ref. [39] use the following approximation of specific hydrogen output (hydrogen output per input electrical energy) h:

$$h(P_{ely}) = \frac{37.3\ kg/MWh}{1.5 + \frac{7.5\cdot 10^{-6} m^2/A\cdot P_{ely}}{P_{ely,max}} J_0} \tag{1}$$

where h is the specific hydrogen output (kg/MWh), P_{ely} is the input electrical power, $P_{ely,max}$ is the maximum power of the electrolyzer and J_0 is the nominal current density. Typical nominal current density for PEM is 6–25 kA/m^2 [40]. The relationship between load and efficiency depends on the construction of the electrolyzer stack [8]. In addition, auxiliary devices such as rectifiers and pumps manifest different efficiency functions.

It is important to take the part-load efficiency into account to enable the possibility to benefit from operating at partial load. To avoid quadratic model formulation [34], we resort to piecewise linear modeling of the consumption as function of the hydrogen output H with four intervals as shown in Eq. (2). Fig. 1 shows the resulting specific consumption. Compared to [34], the difference at high loads is due to different assumption of full-load efficiency (in our case 47 kWh/kgH_2).

$$\frac{dP_{ely}}{dH} = \begin{cases} 41\frac{kWh}{kg}, & \frac{H}{H_{max}} \le 0.25 \\ 45\frac{kWh}{kg}, & 0.25 < \frac{H}{H_{max}} \le 0.5 \\ 49\frac{kWh}{kg}, & 0.5 < \frac{H}{H_{max}} \le 0.75 \\ 53\frac{kWh}{kg}, & \frac{H}{H_{max}} > 0.75 \end{cases} \tag{2}$$

The direct capital cost of electrolysis show economies of scale up to capacities of about 1 tH_2/d (about 2 MW_e), beyond which costs rise nearly linearly [36,41]. A wide range of estimates, current and future, have been published [8]. Bertuolucci et al. [37] anticipate the future investment cost of PEM electrolysis in 2030 to be 760 €/kW but with wide range of uncertainty 250–1270 €/kW. A different future prediction was given by Ref. [42], who estimate the PEM electrolysis investment cost in 2030 for a 5 MW plant to be 960 €/kW and for large 100 MW plant 300 €/kW. Ref [43] predicts that the investment cost for the 100 MW plant in 2030 will be 350 €/kW. Ref. [8] predicts 250–1250 €/kW and [44] 600–1000 €/kW in 2030.

400 €/kW was used as investment cost and fixed annual operation and maintenance costs were assumed to be 2% of the capital cost [45]. Lifetime of current PEM electrolysers has been reported as 60,000–100,000 h [8].

Air separation

Cryogenic distillation of air is the only commercially available technology for large-scale industrial applications [46]. It also

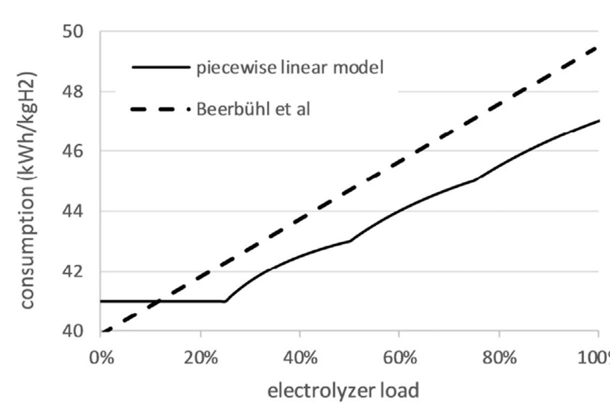

Fig. 1 – Modeled specific consumption *u(H)* as function of electrolyzer load. Also the model used by [34] is shown.

enjoys the advantage of being able to produce several gases at low incremental capital and energy cost [47]. The process also has the advantage of being able to economically liquefy the oxygen which is produced in the electrolysis plant, and store it for later use [4].

Dana et al. [5] state the realistic power consumption of ASU as 61 kWh per tonne of nitrogen while Morgan [28] state the value 108 kWh/tN_2 at 8 bar based on his own calculation. For gaseous nitrogen compressed to 40 bar, theory and public technical data yield the result 243 kWh/tN_2 [48], quite close to that used by Morgan, when the pressure difference is taken into account. In our model ASU was combined into the power consumption of NH_3 synthesis.

The capital cost of ASU was estimated at 1.45 M€/(tN_2/h) [28]. In this study we assume total O&M cost of 2% of investment per annum.

Intermediate hydrogen storage

Electrolyzers can operate at elevated pressures but mechanical compression is still required to feed the intermediate hydrogen storage [49]. Hydrogen compressors needed to fill the intermediate storage consume a large amount of electricity and capital. Theoretical electricity consumption of hydrogen compression was estimated at 2.2 kWh/kgH_2 and 3.0 kWh/kgH_2 for compression to 440 bar and 880 bar respectively [50], assuming suction pressure of 20 bar. We may note that this equals 6.6–9.1% of the fuel's lower heating value and represents a significant efficiency penalty. As can be noted below, however, the pressure can be utilized in feeding the synthesis reactor. A base case estimate for the compressor investment cost is $15,600/($kgH_2$/h) and optimistic estimate $7800/($kgH_2$/h) [51]. We used 11,000 €/(kgH_2/h), which translates to approximately 230 €/kW of electrolysis input power.

Aicher et al. [52] mention 5.8 €/kWh_{H2} as the cost of pressurized hydrogen storage. Parks et al. [51] estimated the cost of storage tanks operating at 172 bar to be $470/$kgH_2$ and storage tanks operating at 875 bar even $1400/$kgH_2$. The cost of 700 bar tanks has been estimated at $460 kgH_2 [53]. Schoenung [54] states the current cost to be $500/$kgH_2$ and low-end target cost $80/$kgH_2$.

We assume that the storage runs unattended and incurred labor cost are thus minimal. Fixed annual maintenance costs were assumed to be 1% of capital costs.

Ammonia synthesis

The most common process for NH_3 synthesis is the Haber-Bosch process. The process combines elemental hydrogen and nitrogen under high pressure and temperature. The reaction is exothermic, with 2.6 MJ/$kgNH_3$ of heat released in the reaction. The Haber–Bosch-process is normally optimized for continuous mass production; however, reconfiguration for dynamic production does not seem to be out of reach [55]. The minimum load could be as low as 20% [34] or 30% [33]. The process is normally shut down only for maintenance and our assumption was thus that the synthesis process is running continuously.

The process contains compressors which consume electricity. Morgan [28] estimated the power requirement for a 300 tonnes per day plant to be 8.0 MW, which leads to specific consumption of 0.64 MWh/tNH_3. However, most of this power was used for feed stream compression where hydrogen was assumed to be fed at STP and nitrogen at 8 bar. In our case hydrogen is fed from the intermediate storage, and thus the energy requirement is much lower. Hydrogen and nitrogen are fed into the reactor at 3:1 stoichiometric volume ratio [30] and the compression work of hydrogen is thus dominant. Dana et al. [5] estimated the synthesis process energy consumption to be 7% of the fuel's heating value, in other words 0.44 MWh/t. Even lower consumption of 0.40 MWh/tNH_3 has been presented [53]. We used specific consumption of 0.64 MWh/tNH_3, which also includes the ASU.

The large heat content produced by the exothermic reaction as well as circulation loop compressors can be exploited in district heating. The exploitable heat was estimated to be 7.9% of the energy input to the whole P2A process [30]; in this study 0.7 MWh/tNH_3 was assumed.

The capital cost of the synthesis process, specific to hourly production capacity, has been estimated to 3000 €/$kgNH_3$ h [33] and 4500 €/$kgNH_3$ h [28]. We used 3000 €/$kgNH_3$ h, and assumed total O&M cost to be 2% of investment.

Ammonia storage

Ammonia is subsequently liquefied, which requires a relatively small amount of energy and capital [28]. Ammonia in large quantities is stored refrigerated to −33 °C in cylindrical double-walled storage tanks. Their capital cost is estimated to be 0.65 €/$kgNH_3$ [28] and 0.9 €/$kgNH_3$ [53], of which the latter was used. The required size of the storage is determined by the simulation, based on the temporal balance between demand and supply.

Solar PV plants

Solar PV has experienced a remarkable cost decline over recent years, and the trend is expected to continue [56]. Increasing efficiency of PV modules reduces capital cost and increases yield per square meter.

Capital costs of PV plants consist of module costs, inverter costs, electrical and structural balance of system costs, cost of installation work, non-labor soft costs such as permitting, engineering and procurement overhead, and developer overhead [57]. Current utility-scale PV plant capital costs have fallen below 100 €/kW [56], although much higher costs have also been reported [57]. Residential systems remain more expensive. Ref. [58] predicts the utility-scale system capital cost in 2050 to be 324–606 €/kW depending on the growth, learning rate and efficiency assumptions. Based on this study and [59], we define two cost scenarios for utility-scale PV: low scenario, with capital cost 330 €/kW and high scenario with capital cost 525 €/kW. We also define a second category of rooftop PV, which includes both commercial and residential installations. Their capital cost in the different scenarios was 630 and 825 €/kW.

The potential of solar PV depends on the available area. Both rooftop and open space ground-mounted installations were considered. While there are many studies calculating the theoretical open space PV potential, only few studies consider the availability of the land area for open space PV. Bossavy et al. [60] estimated the open space PV energy potential in Brittany (France) to be on average 179 Wh/m^2/a, but with considerable variation from less than 100 Wh/m^2/a to more than 400 Wh/m^2/a. This would translate capacity-wise to 0.16 MW/km^2, assuming yield 1100 kWh/kW$_p$/a. Here the area unit refers to total land area in the region – subtraction of restricted areas is included in the coefficient. Peters et al. [61] estimated the technical potential of open space PV in Germany to be 143 GW, which translates to 0.4 MW/km^2 (again referring to total land area). Schmidt et al. [62] estimated the technical potential of photovoltaic power plants alongside rail road tracks and motorways in different European countries. Furthermore, considering also possible dual use of land by combining agricultural fields and PV farms [63], the future potential may be even higher. Here we use the value 0.35 MW/km^2 but reduce the potential in the northern parts of Finland, Sweden and Norway due to great distances and weak grids.

There are also variations in the estimates of technical potential of rooftop PV. It was estimated in Finland by [64] as 34 GW. Schmidt et al. [62] also estimated the technical potential of rooftop PV for European countries; for Finland their estimate was significantly lower at maximum 9 TWh/a. For Germany they estimate 118–180 TWh/a, while Peters et al. [61] present a much lower capacity value of 65 GW, which translates to 62 TWh/a assuming 950 h/a full load hours. Schmidt et al. [62] also present a formula for estimating the roof area per capita in residential buildings as

$$A_{roof} = 0.8 \cdot 0.981(GDP)^{0.358} \quad (3)$$

where A_{roof} is the roof area per capita in square meters and GDP is the gross domestic product per capita in US dollars corrected with purchasing power parity. We assume that there will not be significant differences between the GDP in different countries of the area and therefore population can be used as a driving parameter for the roof area.

Table 1 shows the PV resulting technical potential used in this study. For the simulation model the potentials were further divided into subareas based on population and area estimates.

Wind power

While wind power as a more mature technology is not likely to achieve the cost reductions which are expected for PV, the cost of energy production is still expected to decrease. While learning curves have for long been used as a tool to forecast future outcomes [65], they contain the implicit assumption that future trends are expected to replicate past ones. Engineering assessments can provide an invaluable complement for learning curves. The results of an expert elicitation survey [65] suggest that by 2050, the levelized cost of energy (LCOE) from onshore wind power in the most likely scenario will decrease by 35% compared to 2014. The cost reduction will be the result of several factors such as reduction of capital cost, operating cost and increase in project lifetime and capacity factor. Coherent LCOE reduction of 30% was achieved by [66]. Capital cost of turbines in Danish conditions is predicted to drop from current 1070 €/kW to 830 €/kW by 2050, with uncertainty range 700–1000 €/kW [66].

LCOE of offshore wind power, both fixed-bottom and floating, is expected to decrease by 38–41% as result of the abovementioned factors as well as reduced cost of financing [65]. Capital cost is expected to decrease by 12% whereas ref. [66] uses learning rate analysis to predict that offshore wind power especially in Denmark will experience capital cost reduction of 40%, from 2800 €/kW to 1700 €/kW including the grid connection, until 2050. Ref. [66] also predicts that additional changes in O&M cost, capacity factor, plant lifetime lead to reduction of LCOE of roughly 50%. Ref [67] finds a large LCOE reduction potential for offshore wind until 2030, the LCOE in 2030 being 50–65 €/MWh in part of the Baltic Sea and North Sea area.

Onshore wind power potential in different countries used in the study is shown in Table 2. For the simulation model, onshore wind power was further divided into different subareas of countries and three different cost categories. For offshore wind, only the economic potential which was seen to go below 65 €/MWh was included in the study as more expensive resources would not have been utilized.

Hydro power

Hydro power in Nordic countries is an abundant source of renewable energy and an excellent provider of flexibility. However, the construction of new reservoirs is controversial and the possibility of capacity expansion is limited. For these reasons, the existing plants and reservoirs were assumed to remain as they are. The expansion of pumped hydro plants, which connect to existing reservoirs is possible and large potential exists especially in Norway. The maximum potential in Norway was set to 9 GW and in Germany 5 GW.

The heat sector

The district heating sector is a large consumer of energy in North European countries. The annual heat demand in the

Table 1 – PV potentials in different countries.

Country	Rooftop [GW]	Open space [GW]
Denmark	19.1	13.9
Estonia	4.1	15.7
Finland	18.7	48
Germany	185	125
Latvia	5.7	22.5
Lithuania	8.7	22.8
Norway	19.8	48.8
Poland	120	109
Sweden	31.4	65

Table 2 – Wind power potentials in different countries [62,67,88].

Country	Onshore GW	Offshore GW
Denmark	12	124
Estonia	9	0
Finland	65	21.8
Germany	194	62.9
Latvia	24	23.4
Lithuania	25	12.7
Norway	84	40
Poland	80	30.9
Sweden	87	18.6

region was assumed to slightly increase to 530 TWh [68,69]. Heat pumps, CHP plants and boilers fired with renewable fuels were assumed to be responsible for district heat generation. Heat storages are important element components in the district heating network which can decouple heat generation and consumption. According to Schmidt and Miedaner [70], the investment cost of tank thermal storage in the 10,000 m^3 range is between 150 and 200 €/m^3, which translates to about 3.8–5.0 €/kWh_{th}. In this work 4.3 €/kWh_{th} was used as investment cost.

Thermal plants

Ammonia was assumed to be utilized in open and combined cycle gas turbines. Cracking of ammonia into its elements in high temperature, followed by combustion of hydrogen is seen as the most feasible option [33]. The efficiency of ammonia cracking and combustion in CCGT was estimated to be 53% (LHV) [33]. Here an optimistic value of 58% was used. The cracker plant, hydrogen burner upgrade in existing gas turbine, and facilities for ammonia storage and unloading were estimated to cost 560 €/kW [33]. The additional cost in case of a greenfield installation was assumed to be smaller than this and was set to 300 €/kW. This cost could possibly be further reduced if the power plant used the same storage and unloading facility with a chemical plant.

Although the main focus is a fully renewable system, it is interesting to estimate the relative competitiveness of other options to achieve nearly zero GHG emissions from the power sector. Thus investments into coal CCS plants using amine scrubbing technology [71] were also allowed. Ref [72] estimates for a large coal plant US$ 1357 per kW of power plant electrical capacity.

Biomass was assumed to be utilized in condensing and CHP plants as well as in district heat boilers. Constraints for annual biomass availability were set for each country.

Stationary batteries

The capital cost of lithium-ion battery plants with 1:6 power-to-energy ratio in 2030 was projected to be 148–198 €/kWh [73]. In this study we concentrate on 2050 cost levels; on the other hand we assumed a 1:1 power-to-energy ratio, which allows the batteries to more readily benefit from providing system reserves but adds to the capital cost. The capital cost was set to 200 €/kWh. The round-trip efficiency of the batteries was set to 90%.

Electric vehicles

Intelligently managing the charging processes of electric vehicles, i.e. smart charging, is considered to be a promising method of supporting the integration of variable generation into the power grid [74]. Within limitations set by the normal use of the vehicles, electric vehicles can provide an excellent short-term buffer for the power system [75].

Only full-electric vehicles (FEV) were included in the simulation. The assumption was that most passenger cars will be electric vehicles by 2050. A conservative value of 60 kWh for the capacity of the EV battery was used. 80% of the capacity was allowed for energy market operations and the vehicles had to have full batteries when departing.

Simulation model

Simulation model

Balmorel-VTT model, developed based on Balmorel model [76], was used to determine the optimal operation of heat and electricity producing plants, P2A and storages. It is an hourly-resolved combined scheduling and capacity planning model, which considers a full year of operation. The components and pathways of energy and gases in the model are shown in Fig. 2.

The studied case and scenarios

The studied region includes the Nordic countries (Finland, Sweden, Norway and Denmark), Baltic countries (Estonia, Latvia and Lithuania), Poland and Germany. The geographical entities in the model were countries which were in case of Sweden, Norway and Denmark further divided into 2–3 transmission nodes. The simulation assumed that all current fossil and nuclear plants will have been decommissioned. The plant cost and lifetime parameters shown in Table 3 and demand parameters shown in Table 4 were used. In the model region the combined consumption of nitrogen fertilizers was 3.7 million tonnes of nitrogen [77], which requires 4.5 million tonnes ammonia as nitrogen carrier.

The focus was on studying the consequences of the uncertainties in electrolysis cost, PV cost and electricity transmission capacity, on NH_3 cost, NH_3 use and NH_3 infrastructure costs. The economics of P2A were also compared to fossil natural gas. Four renewable simulation scenarios (with no fossil fuels allowed) and two scenarios allowing fossil fuels were defined (Table 5). The scenario of low PV cost and low transmission capacities was chosen as the base case to which other cases were compared. In the scenarios of Table 5 the model region was assumed to be self-sufficient with respect to NH_3.

A number of other parameters must also be set. Biomass fuel cost was set to 18 €/MWh and fossil natural gas to 46 €/MWh [78]. The price of the CO_2 emission allowance in the base case was set to 80 €/t [78]. The cost of capital has a large effect on the relative competitiveness of different technologies. A low capital cost of 4–5% has been suggested for energy analyses [79]. Here a higher weighted cost of capital 7% was used.

Results and discussion

Production and investments

Fig. 3 shows the annually produced electrical energy by generation type in both PV cost scenarios. Wind power is the clearly dominant electricity producer in all the sub-regions shown in a cost-minimizing solution with our assumptions; hydro power is larger producer in the individual countries Sweden and Norway. Solar power is small in the Nordic countries. Condensing power has significance in energy terms only in Germany (37 TWh), as Germany does not have

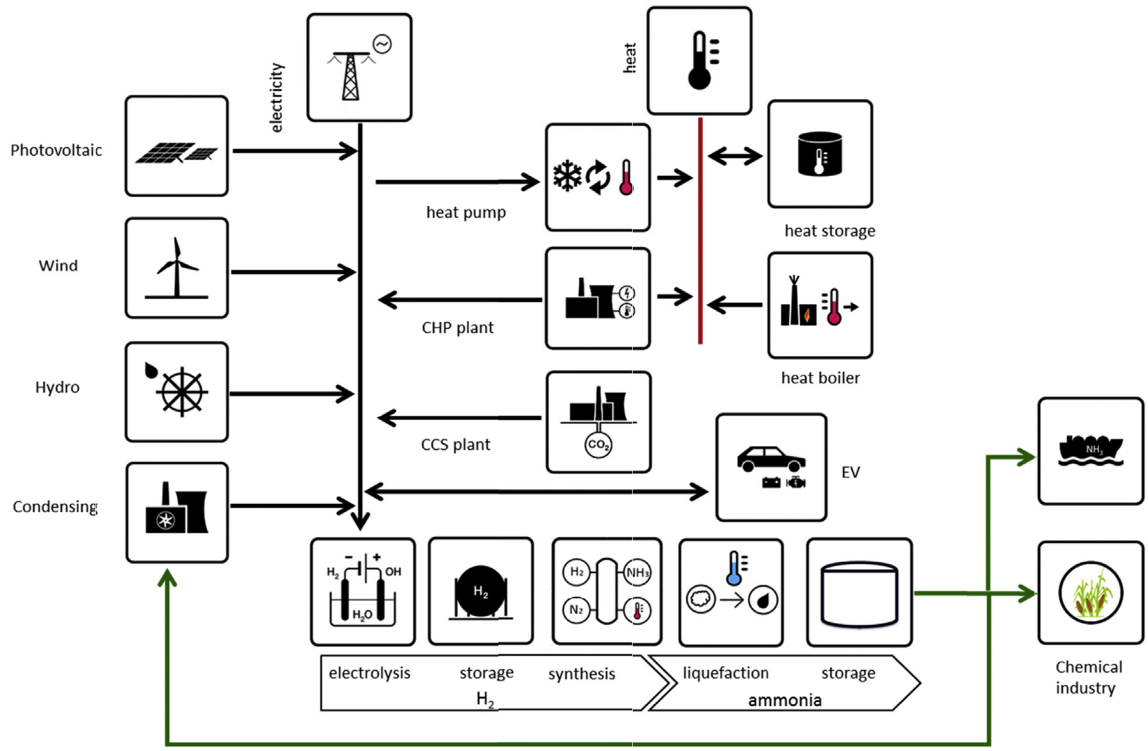

Fig. 2 – Components and flow chart of one region in the energy system model. The power system is shown on the left, the district heating system on the right and ammonia system in the bottom. Different regions are connected through electricity transmission.

Table 3 – Economic parameters used for power and heat generation and storage technologies.

Conversion technology	Fuel	Investment cost €/kW	Annual fixed O&M €/kW	Variable O&M €/MWh	Efficiency	Lifetime
steam CHP	biomass	2000	60	3	0.41	40
steam condensing	biomass	1700	50	3	0.41	40
steam CCS	coal	2900	65	22[e]	0.36	40
CCGT-	NH_3	1200	35	2	0.58	35
OCGT-	NH_3	750	20	2	0.40	30
CCGT-	natural gas					
OCGT	natural gas					
pumped hydro		700	10		0.8[c]	50
solar PV utility		330–520	10			30
solar PV small		630–820	10			30
wind onshore		850–1100	22	1		30
wind offshore		2000	55 €	1		30
battery plant		200[a]	5[a]	2	0.9[c]	15
heat pump		520[b]	15[b]	0.5	2.8[d]	30
heat boiler	biomass	370[b]	3[b]	2.7	0.85	25
heat boiler	natural gas	80[b]	2[b]	0.6	0.9	25
PEM electrolysis		630–930[f]	12		0.71	15
hydrogen buffer		13.5[a]	0.14[a]			30
NH3 synthesis		870[g]	17			20

[a] €/kWh.
[b] €/kW_{th}.
[c] Roundtrip efficiency.
[d] Coefficient of performance.
[e] Including CO_2 storage.
[f] Including compressors.
[g] Including ASU.

Table 4 – Electricity and district heat demand by country.

Country	Electricity demand TWh	Heat demand TWh
Denmark	46	41
Estonia	16	8
Finland	98	39
Germany	650	180
Latvia	15	9
Lithuania	22	11
Norway	125	5
Poland	200	120
Sweden	149	61

Table 5 – Simulation scenarios.

-Scenario	Description
base	PV capital cost 330 €/kW
PV 525	PV capital cost 525 €/kW
high trans	Maximum transmission capacity between Norway and Germany, and between Poland and Baltic countries increased by 150%
high capex	Electrolysis capital cost increased to 930 €/kW (including compression)
gas CO_2 low	Fossil natural gas available; base CO_2 price
gas CO_2 high	Fossil natural gas available; CO_2 price 250 €/t

sufficient access to the balancing capacity of the Nordic hydropower. The condensing plants in Germany are also the main consumer of NH_3 in the energy sector as we will see below. Wood-fired CHP plants were competitive in most countries. Coal-CCS was not profitable in any of the cases, due to high capital and operating costs and low efficiency. Stationary battery plants were not profitable.

In capacity terms, condensing power is much more prominent (Fig. 4), as in practice the capacity adequacy requirement necessitates a large amount of NH_3-fired gas turbines in the absence of natural gas. In Germany also NH_3-fired combined cycle plants are invested in to meet a need for mid-merit plants. Wind power is the largest electricity producer in terms of installed capacity in all the countries.

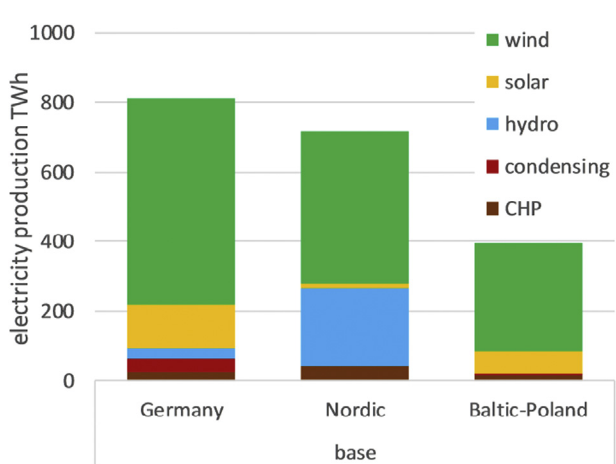

Fig. 3 – Annual electricity generation by generator type in the base case.

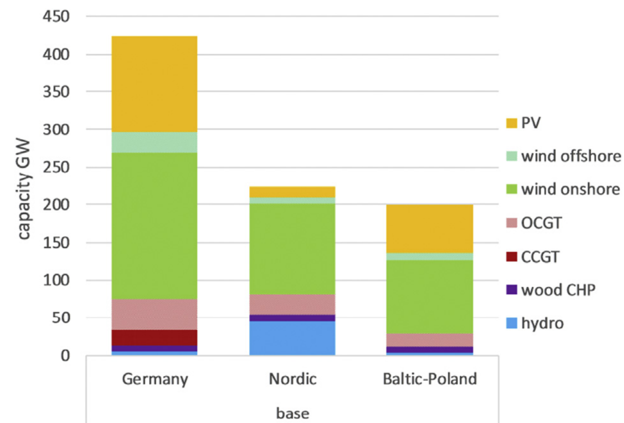

Fig. 4 – Power generation capacity in the base scenario in the different sub-regions of the study.

In scenario "PV525", PV cost decrease follows a more pessimistic path and remains at a higher level (525 €/kW). The optimal PV capacity will be approximately 45% lower in both Nordic countries as well as Baltic countries and Poland (Fig. 5). This is compensated by investment into onshore and offshore wind in all sub-regions, above all Nordic countries. In other words, there is production shift from PV production in Poland to wind power production in Nordic countries. Also wind curtailment is reduced in Germany, which allows a small production increase. The cost increase has only a small effect on PV capacity in Germany because the country is a net importer of electricity and benefits from PV even at the higher price.

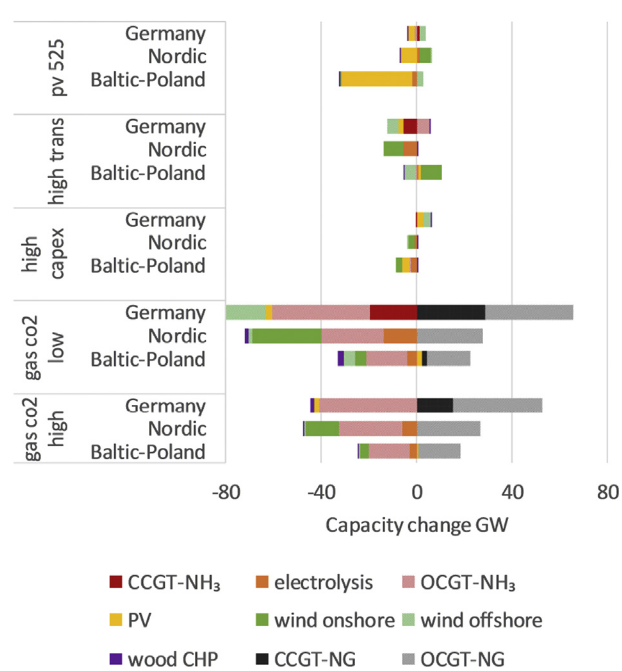

Fig. 5 – Power generation capacity in the different scenarios compared to base scenario.

Open space PV potential was fully utilized in Germany and consequently the more expensive rooftop PV was partially utilized in these regions. A higher potential for open space PV would have resulted in somewhat higher PV capacity, but the driving force limiting PV expansion in the high latitudes is the variability, especially seasonality, of the resource.

In "high trans" scenario, limits for maximum transmission capacity from Poland via Baltic countries to Finland, as well as transmission capacity between Germany and Southern Norway was increased by 150%. In this scenario generation capacity decreases in Germany but is partly replaced by gas turbines to maintain capacity adequacy. Half of the offshore wind capacity in Poland and Baltic countries can be replaced by onshore wind, and wind power capacity in total is increased. In Nordic countries, NH_3 synthesis and wind power capacities can be decreased. If the capital cost of electrolysis is increased ("high capex" scenario), electrolysis capacity is reduced in Baltic countries by 59%, leading to reduction also in wind and PV capacity.

In the fossil scenario "gas CO_2 low", natural gas is used instead of NH_3 within the power and heat sector. Wind energy is reduced in favor of imported natural gas. Generation capacity is decreased in the NH_3 producing Nordic countries also because it is not needed for supplying NH_3 plants. The total reduction in CHP capacity is 28%. Natural gas remains as the dominant peak power fuel until the CO_2 emission price is increased above 200 €/t, where NH_3-fuel reaches viability. At 250 €/tCO_2 (scenario "gas CO_2 high") NH_3 and CO_2 are roughly equal fuels in terms of electrical energy generated. As shown in Fig. 5, the reduction in wind power capacity in the fossil case is not as large when CO_2 emission price is high (scenario "gas CO_2 high").

Ammonia production

In the base scenario, electrolysis capacity in P2A plants amounted to 23.1 GW. There is a clear locational pattern of NH_3 consumption and production: Norway is the main producer and Germany the main consumer. In addition some production took place in Baltic countries and northern Sweden in the base case. Fig. 6 shows that in the base case NH_3 consumption in the power and heat sector was 15.1 million tonnes, almost all of which took place in Germany. NH_3 production was 20.1 million tonnes to accommodate the

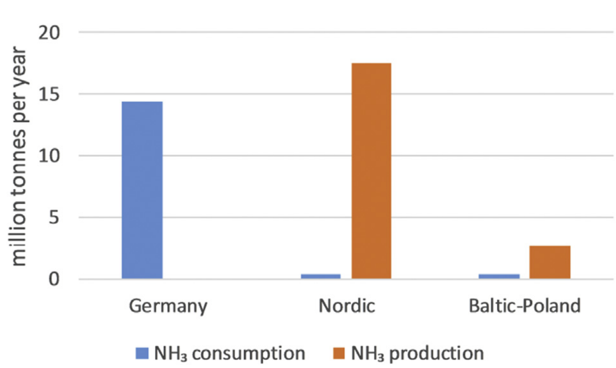

Fig. 6 – Ammonia consumption and production in the base case in the different subregions of the study.

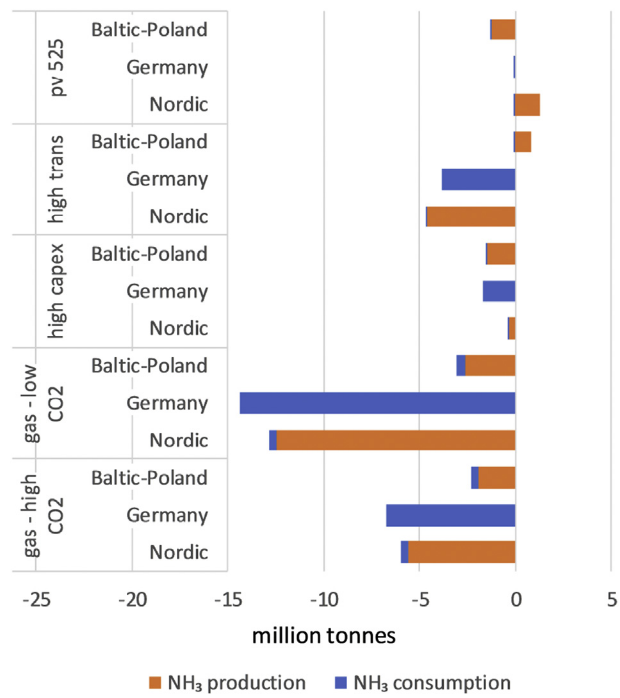

Fig. 7 – Ammonia consumption and production change for the different scenarios, compared to the base scenario.

industrial demand. As shown in Fig. 7, 1.3 million tonnes of NH_3-production is moved from Poland and Baltic countries to Norway with the general production shift from PV to wind power in the pessimistic PV cost scenario "PV 525". The high transmission scenario "high trans", allows decreasing NH_3-production in Norway by 27% because energy can now be transported to Germany via the larger HVDC link. This is accompanied by consumption decrease in Germany. A higher electrolysis capital cost (scenario "high capex") leads to 55% decrease in NH_3 production in Baltic countries.

In the fossil scenario "gas CO_2 low", NH_3 production decreases by 75%, and in Baltic countries and Poland by 100%, because NH_3 is not consumed in the power and heat sector and only industrial demand must be covered. If the CO_2 emission price is then increased to 250 €/tCO_2 the total NH_3 production reaches 12.6 million tonnes. Norway is the dominant producer also in this case.

The balance of production and consumption of NH_3 varies over time, which leads to demand of storage capacity. The global storage level in two simulation cases is shown in Fig. 8. The minimum required storage capacity is 5.4 million tonnes in both cases. We can see two major drops in the storage level, corresponding to periods of low wind power generation.

Costs

We have specified the cost structure of all the conversion and storage plants in the simulation and total costs of the scenarios can therefore be calculated. The cost results are presented as the average cost of energy, which is defined as the total annualized investment cost added to total annual

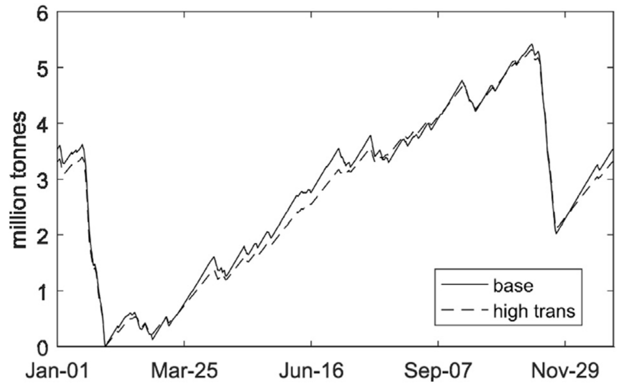

Fig. 8 – Storage level of the aggregated ammonia storage in the model region as function of time in two scenarios.

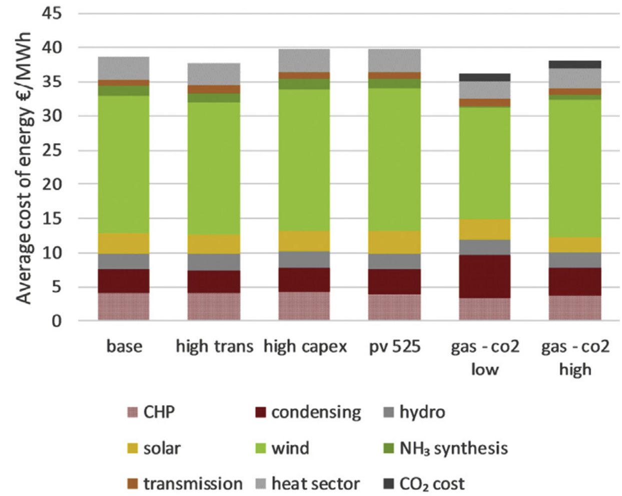

Fig. 10 – Average cost of energy (electricity, heat and ammonia) in different scenarios. NH_3 synthesis includes electrolysis, hydrogen and NH_3 storages.

operation, maintenance fuel and CO_2 emission costs, divided by the total produced energy by all plants. The energy includes electricity, heat and fuel energy stored in synthetic fuels.

Fig. 9 shows the average cost of energy in the base case. Germany suffers from expensive condensing capacity whereas Nordic countries benefit from the affordable hydro power. In Poland and Baltic countries the heat sector was relatively larger and thus also contributes more to the cost. Transmission was relatively more expensive in Nordic countries, which is due to Nordic countries being modeled with 9 separate transmission nodes.

The average cost of energy naturally increases if PV cost decrease follows the pessimistic path (scenario "PV 525"), as shown in Fig. 10. Increasing the limit of transmission capacity (scenario "high trans"), is able to reduce the average cost by 2.3% due to decrease in wind power and P2A investment. The lowest cost is achieved in the case where fossil natural gas was available. The cost of condensing generation increases greatly in this case because of the fuel cost of natural gas. Wind power generation and absolute cost is greatly reduced in this case. The total system cost of the fossil system was 5.6% lower than that of the base case when price of natural gas was 46 €/MWh. The cost of P2A is reduced by 77% due to low demand of NH_3 (scenario "gas CO_2 low"). When the CO_2 emission price is increased to 250 €/tCO_2 the cost optimal share of renewable energy and NH_3 again increases. In this scenario ("gas CO_2 high") NH_3 allows reduction of total system cost by 0.2% compared to a scenario where NH_3 is not used in the power sector.

The marginal cost of NH_3 production in the studied cases varied between 431 and 528 €/t (Fig. 11). Low demand in the fossil case led to low marginal cost of NH_3 while high electrolysis capital cost increased it In the renewable scenarios the contribution of NH_3 production and storage to the average cost of energy was 1.2–1.5 €/MWh (3.1–3.9% of total system cost). In the base scenario 51% of the cost originated from electrolysis, with Haber-Bosch synthesis and storages making up a 49% share. Re-electrification in condensing plants contributed by 3.5–3.7 €/MWh.

Discussion

The fully renewable power and heat sector in the model region was based mostly on wind power because of its low price and

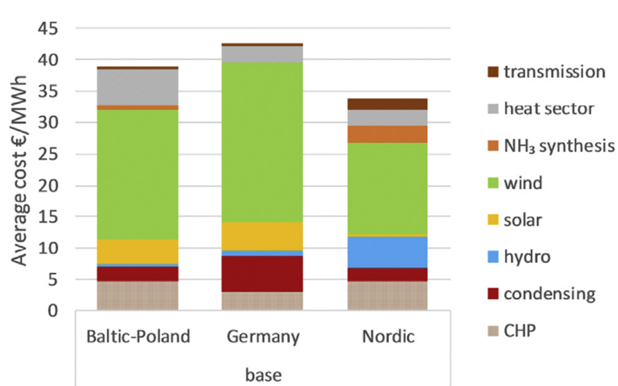

Fig. 9 – Average cost of energy in the base case. The heat sector includes heat generation assets and heat storages. NH_3 synthesis includes electrolysis, hydrogen and NH_3 storages.

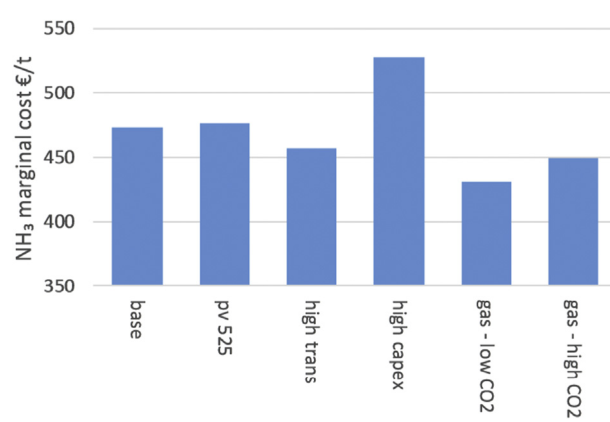

Fig. 11 – Marginal cost of synthetic NH_3 production in different scenarios.

good availability. The result is consistent with Ref. [69,80]. In solar PV the cheaper open-space installations were fully exploited in Germany and Denmark but the more expensive rooftop installations were exploited in any subregion only to small degree. The amount of solar PV generation was slightly higher than in Ref. [69] and clearly higher than in Ref. [80]. This is likely because Ref. [80] included also southern Europe countries, where PV is more competitive. Germany appeared as the greatest power importer, which is a result of the high demand intensity and low capacity factor of wind power. Norway with its good wind resource acted as power exporter. Decreasing PV capacity and increasing wind power capacity as result of increased transmission capacity is consistent with Ref. [80]. In our study, increased transmission capacity decreased P2A production and related losses, which led to decreased need in wind power capacity.

The study did not consider full details within the heat sector but showed that P2A can contribute significantly to district heat production depending on plant siting. As explained in Section Power-to-ammonia (P2A) plant in our simulation waste heat was extracted from the Haber-Bosch process. This is high-quality heat which may be exploited in space heating or certain industrial processes. Waste heat from electrolysis was not exploited. This is different from the analysis of Ref. [81] where the waste heat from electrolysis was upgraded with metal hydride heat pump. This is an emerging technology for which reliable cost and lifetime information is not available. Heat integration is possible but is limited by the low operating temperature of PEM electrolysis. It and has been implemented in demonstration projects [8] and can be considered for future low-temperature district heat networks. Furthermore, unlike in Refs [81,82], hydrogen or ammonia are not used for heating because they turn out to be too expensive for this purpose.

The contribution of P2A in the district heating sector was limited by regional mismatch of heat availability and demand. The largest P2A installations were located in the sparsely populated northern Norway. Heat integration is further complicated by conflicting siting requirements for the plants in the regional level, which is not resolved by the model. Largest part of (70%) district heat in the model region was provided by electrically driven heat pumps, followed by biomass-fired CHP plants. Affordable large heat storages can provide flexibility by relieving heat pumps during times of peak power demand.

The simulation also included the integration of EV and their flexibility, which was important especially on daily level. The high EV penetration is of course conditional on material constraints not becoming a limiting factor [83,84].

We see that P2A serves three roles in the results of this study. Firstly it produces renewable ammonia for the fertilizer industry; secondly it acts as energy vector to transfer energy in time, i.e. acts as energy storage; thirdly it acts as energy vector to transfer energy in space, i.e. acts as substitute for power transmission.

Renewable NH_3 could be produced at a price which is not significantly different than the world market price today. Currently the price is highly dependent on the price of the main feed stock (natural gas) and in recent years has varied between 300 and 700 USD/t in Western Europe. The increasing price of natural gas [78] contributes to the competitiveness of P2A. The resulting marginal cost of power-based NH_3 is also well in line with the near-term levelized production cost of 655 USD/t in Ref. [32]. Of the chosen parameters the electrolysis capital cost had highest impact on NH_3 production cost.

The application of P2A as a long-term storage method is evident in the results. We see that a fairly small storage capacity of NH_3 was enough to balance the variation in regional production and use of ammonia during the simulated year. A considerably larger storage is needed if the system prepares for longer periods of poor wind power output using NH_3. The size of this storage should be studied more carefully with longer weather patterns.

The third role as replacement of transmission capacity was also clear. The NH_3 trade between Nordic countries and Germany clearly decreased with increased transmission capacity. Also, it was clear that increasing the transmission capacity was a cheaper option. However, taking into account transmission constraints within model sub-regions could change the result. Models which also see the transmission lines inside countries and country provinces tend to see a lower overall level of grid expansion at the cost-optimal level than studies which aggregate each country to a single node [80].

Despite the low capital cost assumed for PEM electrolysis, electrolysis was the dominant source of costs in NH_3 production, as opposed to NH_3 synthesis or storage.

In the non-renewable scenarios, where consumption of fossil natural gas is allowed, natural gas is used instead of NH_3 as a more competitive fuel. The gas price or CO_2 emission price must rise to a high value, above approximately 70 €/MWh or 200 €/tCO_2 respectively, before NH_3 becomes competitive in the power and heat sector compared to natural gas.

In a subcontinental optimization model individual plants cannot be tracked and consequently optimizing NH_3 logistics and plant locations would be rudimentary at best. This is an area of future work, possibly using some form of co-optimization. At least the following factors should be considered: economies of scale, transportation modes and integration of P2A with heat consumers, and possibly with oxygen consumers. Significant economies of scale can be reached in PEM electrolysis even above plant sizes of several megawatts [43]. Bosch-Haber processes have so far pursued the highest possible efficiency by large size. Ref. [29] compares NH_3 pipeline transmission favorably against electricity transmission, and presents capital cost USD320/MW-km for a 10 inch diameter pipeline. Considering the cost figures presented for liquid CO_2 transport [85,86], and district heat pipelines, which use largely similar technology as NH_3 pipeline, this can be viewed as an optimistic number. We estimate that the NH_3 pipeline has the possibility to be cost efficient only above several hundred megawatts capacity. Our initial estimate for the capital cost of such pipelines is approximately 1500–2500 €/MW-km and, assuming a high capacity factor, total cost 0.02–0.04 €/tonne-km. This agrees with the tariff presented for the NH_3 pipeline in United States Midwest, USD 0.018/tonne-km [87] but depends on terrain and the needs to pass existing infrastructures. For longer distances ship is the most economical mode. Relying on the numbers presented for CO_2 transport the shipping cost for 1800 km distance, such as from northern Norway to Germany, is approximately 11–16 €/t [85]. Thus a possible configuration is a relatively large P2A plant which is, depending on the location of generating plants and possible heat consumer, connected to ship terminal by pipeline. At the destination port, shipment may continue by pipeline, railcar or truck depending on the volume. Co-locating NH_3-fired power plants with industrial NH_3 consumers can reduce the storage and transportation cost. We can thus expect that the average transportation cost remains below 30 €/t or approximately 6% of the marginal production cost and based on this we believe that including ammonia transportation is not likely to change the current conclusions drastically.

Conclusions

Hourly power and district heat energy balance was maintained in a simulation of the Northern European countries, in a system based on renewable wind, hydro and solar power and power-to-ammonia energy storage, where cost estimates for year 2050 were used. While the fossil system with lower CO2 prices reached a lower total cost, with our assumptions power-to-ammonia did not have a large impact on the system costs while enabling a fully renewable power sector with the caveat that power system stability was not considered. Power-to-ammonia offers a cost effective form of long term energy storage that will be highly beneficial for a power system relying heavily on variable power generation. Production cost of NH_3 was not significantly higher than world market prices which have been encountered in recent years. Thus renewable NH_3 could be a viable alternative for the fertilizer sector, enabling further de-carbonization within the industrial sector.

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