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Blue hydrogen and industrial base products: The future of fossil fuel exporters in a net-zero world

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A B S T R A C T

Is there a place for today's fossil fuel exporters in a low-carbon future? This study explores trade channels between energy exporters and importers using a novel electricity-hydrogen-steel energy systems model calibrated to Norway, a major natural gas producer, and Germany, a major energy consumer. Under tight emission constraints, Norway can supply Germany with electricity, (blue) hydrogen, or natural gas with re-import of captured CO_2. Alternatively, it can use hydrogen to produce steel through direct reduction and supply it to the world market, an export route not available to other energy carriers due to high transport costs. Although results show that natural gas imports with CO_2 capture in Germany is the least-cost solution, avoiding local CO_2 handling via imports of blue hydrogen (direct or embodied in steel) involves only moderately higher costs. A robust hydrogen demand would allow Norway to profitably export all its natural gas production as blue hydrogen. However, diversification into local steel production, as one example of easy-to-export industrial base products, offers an effective hedge against the possibility of lower European blue hydrogen demand. Looking beyond Europe, the findings of this study are also relevant for the world's largest energy exporters (e.g., OPEC+) and importers (e.g., developing Asia). Thus, it is recommended that large hydrocarbon exporters consider a strategic energy export transition to a diversified mix of blue hydrogen and climate-neutral industrial base products.

1. Introduction

The global energy transition is gaining momentum with net-zero emissions by 2050 becoming a broadly recognized long-term target. Even though current pledges continue to fall far short of requirements (CAT, 2021), investment in clean energy is accelerating, promising a more rapid transition.

In parallel, investment in fossil fuels has dwindled, exemplified by the bleak outlook for oil & gas producers presented in the 2020 IEA World Energy Outlook report (IEA, 2020c). When compared to estimates before the pandemic, the Sustainable Development Scenario (SDS) halves the net-present value of all oil and gas production up to 2040. The SDS only achieves carbon-neutrality by 2070, so this value decline will be considerably worse when targeting 2050. In fact, a recent IEA report on reaching net-zero by 2050 states that there is no need for new fossil fuel supply in this scenario (IEA, 2021).

Still, the global economy will require large quantities of fuels for many decades to come. Although electrification is set to continue at a high rate, electricity supplies only about 20% of global final energy today and less than 30% by 2040 in the SDS (IEA, 2019b). The renewables-focused REMAP scenario of IRENA targets 38% electricity share by 2040, adding that current progress is off track (IRENA, 2019). Bloomberg New Energy Finance sees electrification only increasing to 24% by 2050 (BNEF, 2020). Total energy demand is also set to remain robust due to the rapid developing world growth.

Given the expected demand growth for clean fuels for decarbonizing sectors like industry and long-distance transport, hydrogen production from natural gas with CO_2 capture and storage (CCS), also known as blue hydrogen, emerges as a vital technology class for oil & gas producers. The thermochemical conversion of natural gas to hydrogen is a well-known and efficient process that lends itself well to existing pre-combustion CO_2 capture technologies with the potential for substantial future efficiency gains from emerging technologies like chemical looping (Osman et al., 2021). In addition, on-site blue hydrogen production by oil & gas producers with direct reinjection of CO_2 for

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Nomenclature

Acronyms

ASEAN	Association of Southeast Asian Nations
CCS	CO_2 Capture and Storage
DNV	Det Norske Veritas
DRI	Direct Reduced Iron
IBPs	Industrial Base Products
GSR	Gas Switching Reforming
GSRH2	Dedicated H_2 GSR plant
H2CC	Hydrogen Combined Cycle
H2GT	Hydrogen Gas Turbine
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
NGCC	Natural Gas Combined Cycle
OCGT	Open Cycle Gas Turbine
OPEC	Organization of the Petroleum Exporting Countries
SDS	Sustainable Development Scenario
SMR	Steam Methane Reforming
VRE	Variable Renewable Energy

Symbols

δ	Demand (MW)
η	Efficiency (%)
ι	Import rate (MW or ton/h)
C	System costs (€)
G	GDP-normalized system costs (% GDP)
E	CO_2 emissions (ton)
e	Specific CO_2 emissions (ton/MWh)
g	Production rate (MW)
GDP	Gross domestic product (€)
p	Price (€/MWh or €/ton)
$\bar{p}$	Weighted average price (€/MWh of €/ton)
s	Rate of CO_2 storage (ton/h)

Sub- and superscripts

exp	Exports
GER	Germany
n	Index for nodes
n_{GER}	Index for Germany nodes (North and South)
NOR	Norway
p	Index for products
t	Index for timesteps

enhanced oil/gas recovery can decarbonize fossil energy extraction while simultaneously enhancing profitability and avoiding challenges with long-distance CO_2 transmission pipelines and methane leaks from natural gas distribution infrastructure. The alternative; green hydrogen from renewables and electrolysis, involves a trade-off between the cost of input electricity and the achievable capacity factor, including the additional equipment needed for handling intermittently produced hydrogen (Cloete et al., 2021). Overall, a technology-neutral hydrogen approach is required for a practical and cost-effective transition (Hydrogen4EU, 2021; van der Spek et al., 2022).

One important challenge with hydrogen is that it is considerably more difficult to store and export than fossil fuels. It has more than 3x lower volumetric energy density than natural gas and liquifies at much lower temperatures. Pipeline transport can be economical for trade between neighbouring countries, but trade on the much larger international market is more challenging. The IEA has studied different options for hydrogen export over long distances (IEA, 2019a), finding that ammonia is generally most attractive, even though it involves considerable additional costs related to the extra energy conversion steps.

A relatively unexplored pathway for clean energy exports is offered by industrial base products (IBPs). Such products can be produced in energy-rich regions and the embodied energy conveniently exported. Ammonia for industrial use (e.g., fertilizers) and methanol are promising options, but the largest clean energy export potential comes from steel and cement that represent 10% (direct and indirect (IEA, 2020b)) and 7% (direct process emissions and heat generation (Andrew, 2018)) of global CO_2 emissions, respectively. Steel production via hydrogen from renewables has seen a significant increase in research attention recently with studies indicating CO_2 avoidance costs of 64–180 $/ton in Norway (Bhaskar et al., 2022) and 67 $/ton in Australia (Gielen et al., 2020) with slight production cost declines if steelmaking plants can be operated in a highly flexible manner to follow variable renewables (Toktarova et al., 2022).

Relocation of industry to regions with excellent renewable energy resources or large CO_2 storage capacity (Bataille et al., 2021) is increasingly recognized as a method to reduce decarbonization costs. Indeed, shipping energy-intensive industrial products internationally is relatively cheap. For example, intercontinental coal transport costs are around $10/ton (IEA, 2020a). One ton of clean steel would avoid about 1.8 tons of CO_2 and one ton of clean cement clinker about 0.9 tons. Export of avoided emissions from regions with cheap energy and CO_2 storage capacity can therefore be done at an affordable cost in the order of $10/ton CO_2[1]. For perspective, transmitting renewable electricity at a 50% capacity factor via a 1000 km HVDC line with assumptions used in the model from this study will cost about 54 $/MWh. If this electricity displaces NGCC power production at 325 kg-CO_2/MWh, the CO_2 avoidance cost is 166 $/ton (or less than half of this value when the imported electricity displaces coal power). For a 1000 km hydrogen pipeline, avoiding CO_2 emissions from SMR at 260 kg-CO_2/MWh would cost about 20 $/MWh or 77 $/ton-$CO_2$.

Today, many heavy industries are operated using abundant, locally produced or imported coal. Without a price on CO_2, using coal is the cheapest option in most world regions. Most of the ~10% of global coal supply that is internationally traded has free on board costs of less than $10/MWh (IEA, 2020a), and the remaining ~90% that is locally produced will be even cheaper. Coking coal used for steelmaking is about twice as expensive and more commonly imported. However, with a CO_2 price of $100/ton, coal costs increase by about $36/MWh, completely changing the scenario. Adding CCS to steelmaking can reduce this CO_2 cost by about 40% (Garcia, 2018), but costs will still be substantially higher than today. In addition, the requirement to position plants in proximity to politically feasible local CO_2 storage will significantly reduce the amount of profitable local heavy industry. These factors will greatly increase the scope for international imports of clean IBPs in a net-zero world.

This study uses a novel coupled electricity-hydrogen-steel energy systems model to investigate the potential of exporting clean energy derived from natural gas, hydropower, and wind as electricity, hydrogen, or clean IBPs. The model is applied to a case study with Norway as the energy exporter and Germany as the energy importer, although the findings are also applicable to other energy exporters and importers. This limited geographical scope allows the system to be simplified while still capturing the main dynamics of the problem. The primary objective and novelty of the study is to compare four different clean energy export vectors available to Norway and other energy exporters:

[1] Assuming clinker is about as expensive to transport as coal, while transport costs of finished steel products are about twice as high.

- Continued natural gas exports with optional imports of CO_2 for storage in Norwegian reservoirs
- Blue hydrogen pipeline exports
- Electricity exports via HVDC cables
- Local production and export of IBPs (exemplified by steel)

The model shows that blue hydrogen is an attractive option that allows Norway to continue profitable energy exports and Germany to achieve cost-effective decarbonization without local CO_2 capture. However, clean steel exports become highly profitable if steel prices rise beyond current levels, while also offering an effective hedge against scenarios with lower blue hydrogen demand. The model shows that Norway enjoys high profit margins on its hydrogen and steel exports when prices are set by green hydrogen production in Germany. Overall, a commitment to replace fossil fuel exports with blue hydrogen and IBPs appears to be a sound long-term strategy for natural gas exporters.

2. Review of future energy scenarios

Many energy scenarios have explored the German energy system in 2050. In general, it can be said that the decarbonization of energy end-use sectors increases the demand for both clean electricity and clean fuels, especially hydrogen (Ruhnau et al., 2019). Recent scenarios focussing on a 95–100% reduction in CO_2 emissions find that the final energy demand increases to about 823 TWh electricity (up from ~500 TWh at present) and 225 TWh hydrogen (up from ~50 TWh), as shown in Table 1. It is noted that the scenarios include additional electricity demand for conversion to hydrogen and vice versa. Also, considerable additional demand is met via biomass and imported synfuels – 306 TWh and 164 TWh, respectively, in the Agora scenario (Prognos, 2020). Vast gains in energy efficiency are envisioned, halving primary energy consumption while sustaining economic growth (Prognos, 2020).

Interestingly, no mention has been made of the possibility to relocate heavy industry to energy-rich world regions and to import clean IBPs. Instead, local industrial output has been extrapolated using recent growth rates (Jülich, 2019) or technological innovation (Fraunhofer, 2020). As a result, the final energy demand in the industrial sector accounts for about 330 TWh electricity[2] and 100 TWh hydrogen across the three reviewed scenarios. Of this, about 36 TWh electricity and 72 TWh hydrogen are for steel production.[3]

The Norwegian system is already highly decarbonized and electrified due to the country's large hydropower resources and small population. However, the degree of electrification is set to increase from 45% today to 61% in 2050 (DNV, 2020). This results in an expected 50 TWh/year increase in domestic demand, largely due to electrification of the offshore industry and road transport. About 20 TWh/year of hydrogen demand is forecast (DNV, 2020), mainly from the manufacturing sector.

Table 1
Final demand for clean electricity and hydrogen in German decarbonization scenarios.

Study	Final electricity demand (TWh)	Final hydrogen demand (TWh)
Agora Energiewende (Prognos, 2020)	720	110
Fraunhofer ISE (Fraunhofer, 2020)	1000	265
FZ Jülich (Jülich, 2019)	750	300
Mean	**823**	**225**

Norway has only minor iron and steel activities today, which has been forecast to remain at low levels (DNV, 2020). Regarding natural gas exports, official projections see a substantial decline starting around 2030 and extrapolations of this trend reach production of about 600 TWh/year by 2050 (Norsk Petroleum, 2021). The DNV projection is more optimistic, seeing constant output until 2040, followed by a gradual decline to about 1000 TWh/year by 2050 (DNV, 2020).

3. Methodology

The following subsection presents model structure and output metrics conserved in the study. Supplementary Material with this submission details the equation system and the technology cost and performance assumptions. The full model, implemented in GAMS, is available online[4] together with detailed data (including timestep-resolved plots) from all cases presented in this work.

3.1. Model structure

The novel electricity-hydrogen-steel energy systems model developed for this work couples an energy exporter (Norway) to a large importer (Germany) to investigate the relative attractiveness of various clean energy export vectors. North and South Germany are modelled separately to capture the effects of high wind resource availability in the North and large demand in the South.

One representative year (2018) is considered with the objective to minimize total system cost by optimizing investment and hourly dispatch of a broad range of electricity, hydrogen, and steel production, transmission, and storage technologies, as well as imports/exports. The optimization is done without considering existing infrastructure, thus representing a long-term view. Technology costs for Europe in 2040 are considered in annualized terms. The Supplementary Material contains more details about technology costs and performance as well as a sensitivity assessment to key assumptions.

The following technological options are available for deployment as large-scale, centralized plants:

- Eleven different electricity generators: Run-of-the-river and reservoir hydropower, onshore and offshore wind, solar PV, natural gas combined cycle plants with and without CCS, open cycle gas turbines, hydrogen combined and open cycle plants, and gas switching reforming (GSR)[5] for flexible power and hydrogen production with CCS (Szima et al., 2019).
- Pumped hydro and lithium-ion batteries for electricity storage.
- Four clean hydrogen technologies: Steam methane reforming (SMR) with CCS, water electrolysis, the flexible GSR technology mentioned previously, and dedicated GSR hydrogen plants that achieve somewhat higher hydrogen production efficiency.
- Fluctuating hydrogen production can be stored in salt caverns or dedicated hydrogen storage tanks. Salt caverns are cheap but have limited charge/discharge rates and spatial constraints, whereas tanks are more expensive but do not face the constraints of salt caverns.
- Additional hydrogen can be imported via clean ammonia from the world market and reconverted to hydrogen in NH_3 cracking plants included in the model.
- Steel is produced via the H_2-DRI process (Pei et al., 2020) using inputs of clean hydrogen and electricity produced and delivered using the technologies outlined above. The potential for more efficient steel production via direct integration of natural gas reforming with

[2] 220 TWh traditional +130 TWh new.
[3] Assuming 40 Mt/a steel and 0.9 MWh/t electricity as well as 1.8 MWh/t hydrogen.

[4] https://bit.ly/3krjzB9.
[5] GSR is a novel process technology that uses the chemical looping principle to supply heat to natural gas reforming with integrated CO_2 capture. It can be designed to operate at steady state while alternating between electricity and hydrogen production depending on market demands.

the steelmaking process is briefly explored in Fig. S2 of the Supplementary Material.

These production and storage technologies are connected via a network of transmission, import, and export options illustrated in Fig. 1 with explanations for the numbering given in Table 2.

This complex collection of production, transmission, storage, and import/export options is optimized to satisfy electricity, hydrogen, and steel demand in both countries at the lowest total cost. Electricity load varies by hour based on historical data, while hydrogen and steel demand are both specified as constant in every hour. Additional electricity demand from continued electrification efforts is also included as constant in every hour.

Total demand in the three regions is given below together with natural gas production based on the studies reviewed in Table 1, with an additional 80 TWh of German electricity demand accounting for grid losses and other demand like direct air capture (Prognos, 2020). Hydrogen and electricity demand for steel production is backed out to isolate expected non-steel hydrogen demand. For Norway, the more conservative official estimates of long-term natural gas exports (Norsk Petroleum, 2021) are considered, with the more optimistic case (DNV, 2020) included in a sensitivity analysis. Norwegian steel demand is not modelled explicitly, given that it is small compared to Germany (~1 Mton/year).

Important cost assumptions are detailed in Table 4. Natural gas production costs (WoodMac, 2016), profits, and pipeline costs amount to a €6/GJ import price for Germany when pipelines are used at a 50% capacity factor – between projections for the IEA Stated Policies and Sustainable Development Scenarios for Europe (IEA, 2020c). A pipeline cost of around €2/GJ was estimated from the difference in market prices in Norway and Germany, but implementation is done as a fixed cost to correctly reflect the cost of occasional fuel supply to low-capacity-factor power plants in systems with high VRE shares. Steel import values are selected to be in line with European prices (MEPS, 2021) and shipping costs are assumed double that of bulk materials like coal. Clean ammonia import prices are taken from the IEA hydrogen report (IEA, 2019a). A high CO_2 price was selected to approach a zero-emission system.

3.2. Output metrics

The results and discussion section presents several output metrics, including breakdowns of the electricity generation mix, export vectors from Norway, and the total annual system cost.

Furthermore, three secondary metrics are derived from the primary model outputs. First, the total CO_2 emissions from the system are calculated by subtracting the total amount of CO_2 stored from the total CO_2 potential of all natural gas used for power and hydrogen production (Equation 1). The potential CO_2 emissions from exported natural gas are reported separately (Equation 2).

$$E = \sum_{t,n} \frac{g_{t,n}^{\mathrm{NG}}}{\eta_n} e^{\mathrm{NG}} - \sum_{t,n} s_{t,n}^{\mathrm{CO_2}} \quad \forall\, t, n \qquad \text{Equation 1}$$

$$E^{\mathrm{exp}} = -\sum_{t,n} \iota_t^{\mathrm{NG}} e^{\mathrm{NG}} \quad \forall\, t, n \qquad \text{Equation 2}$$

Second, the total system cost is split between Norway and Germany and normalized by 2019 GDP to quantify how different scenarios affect exporters and importers. Normalization by GDP is useful for quantifying the broader economic impacts of different energy scenarios. For example, if a given scenario costs 1% of GDP more than the baseline scenario, it will cause a long-term reduction in the achievable economic growth of roughly 1 %-point because this amount of economic activity will need to be permanently redirected from higher economic sectors to the foundational energy sector. Costs related to generation, transmission and storage directly assigned to given nodes (C in Equation 3 and Equation 4) are simple to split between the two countries. Costs for imported products are added (exports are negative imports) based on endogenously calculated shadow prices for electricity, hydrogen, and CO_2, and exogenously specified import and export prices for natural gas and steel.

$$c_{\mathrm{NOR}} = \left(C_{\mathrm{NOR}} + \sum_{t,p} \iota_{t,\mathrm{NOR}}^{p} p_{t,\mathrm{NOR}}^{p} \right) \Big/ GDP_{\mathrm{NOR}} \qquad \text{Equation 3}$$

$$c_{GER} = \left(\sum_{n_{\mathrm{GER}}} C_{n_{\mathrm{GER}}} + \sum_{t,n_{\mathrm{GER}},p} \iota_{t,n_{\mathrm{GER}}}^{p} p_{t,n_{\mathrm{GER}}}^{p} \right) \Big/ GDP_{\mathrm{GER}} \qquad \text{Equation 4}$$

Third, the system-average shadow prices of electricity, hydrogen, and steel are calculated as the demand-weighted average across all timesteps and nodes (Equation 5). Weighted average electricity and hydrogen prices are reported directly, whereas steel prices are reported for Germany as a "steel premium" – the difference between the German weighted average steel shadow price and the exogenously specified international steel export price.

$$\overline{p}^{p} = \sum_{t,n,p} \delta_{t,n}^{p} p_{t,n}^{p} \Big/ \sum_{t,n,p} \delta_{t,n}^{p} \qquad \text{Equation 5}$$

4. Results and discussion

When it comes to exporting clean energy, hydrogen and electricity are commonly considered as possible export vectors. In addition to these standard options, this study also investigates the trading of IBPs. Using the example of Norway and Germany, the following four subsections examine how the export of IBPs, exemplified by steel, plays out relative to other clean energy export vectors.

First, the effect of considering IBPs as an additional export vector is investigated by comparing a baseline scenario (CCS allowed in Norway, but not in Germany) with and without steel trade. Second, alternative policy scenarios tilting more to the green (no CCS in Norway or Germany) or blue (CO_2 capture also allowed in Germany with storage in Norway) sides are investigated with and without steel trade. Third, multiple important factors that can influence the demand for Norwegian blue hydrogen are identified, and their effects are quantified and discussed in the fourth subsection.

4.1. The baseline scenario with and without steel trade

The baseline scenario is tailored to the current state of the clean energy political debate, while assuming a technology-neutral (blue or green) stance on hydrogen. This means domestic renewable energy must supply at least 80% of electricity in Germany and 95% in Norway. Furthermore, CCS is allowed in Norway but not in Germany, where it faces public resistance. This baseline scenario is explored with and without steel trade on the global market. All other model characteristics of the energy system, including the trade of electricity and hydrogen, are freely optimized.

Fig. 2 a & b show details about electricity production, consumption, and trade. Wind dominates production in Norway and North Germany, whereas South Germany relies more on solar due to its low wind resource quality. Germany also generates 8–19% of its power from hydrogen with a small fraction of thermal power production still coming from natural gas in South Germany due to the absence of salt cavern storage to cheaply store hydrogen for low-capacity-factor power production. Norway also generates the permitted 5% of power from natural gas using the GSR technology to assist hydro in balancing fluctuating wind power. Significant electricity consumption from hydrogen production (blue in Norway and green in Germany), pumped hydro, batteries, and steelmaking is also visible. It is noted that pumped hydro and

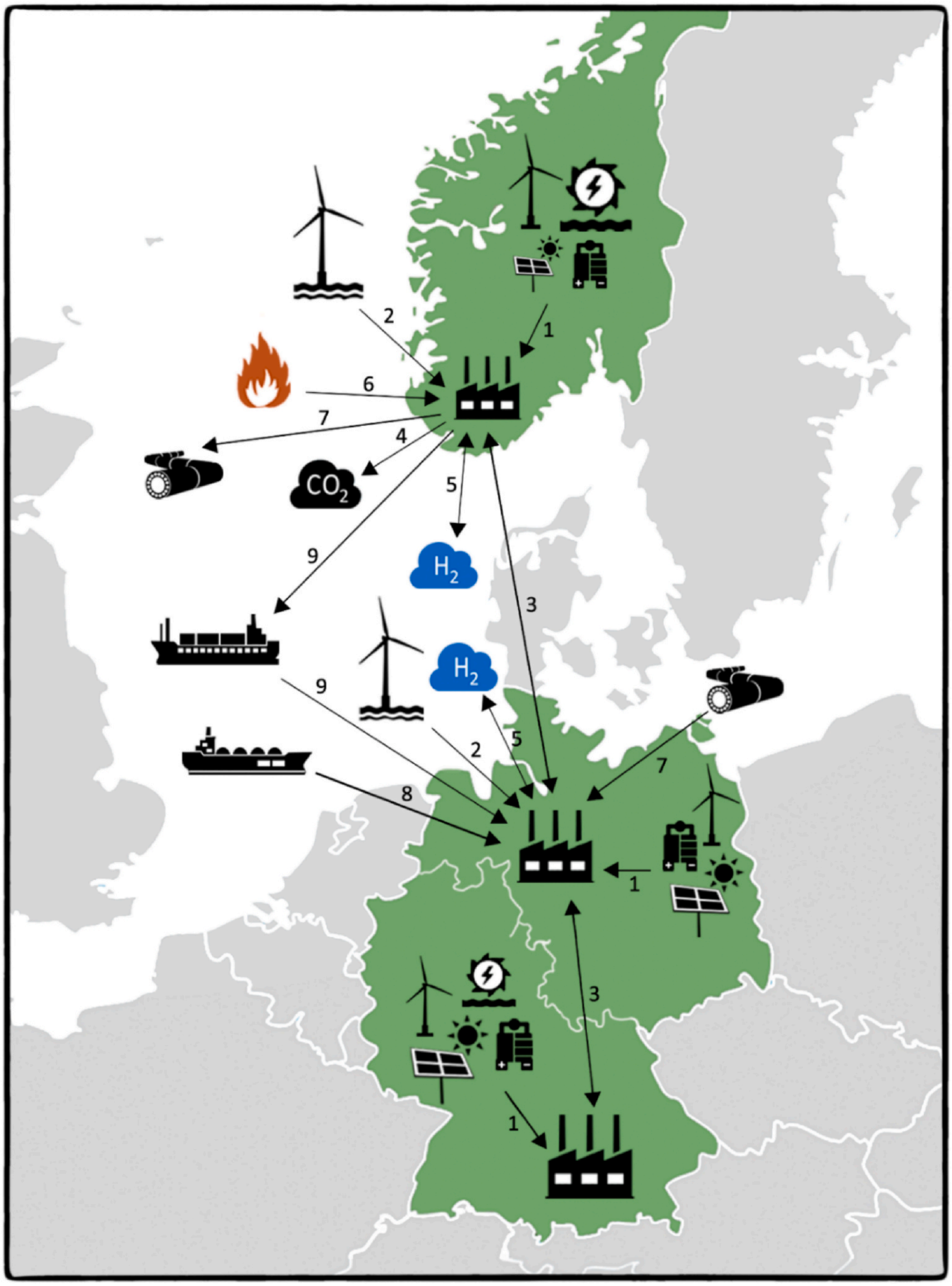

Fig. 1. A graphical summary of the different transmission, import and export elements included in the model. Germany is modelled as separate Northern and Southern regions. The numbers are explained in Table 2.

battery power consumption is shown as the efficiency losses from cycling electricity through these storage technologies.

Regarding trade, Fig. 2 a & b show that South Germany relies on Norwegian electricity imports (transmitted via North Germany) for about a quarter of supply. When steel trade is activated, electricity trade increases even though Norway needs more local electricity for steel production. This increase is driven by higher hydrogen prices (to be discussed below), which cause Germany to displace some hydrogen-fired power production with direct electricity imports (Fig. 2b).

Fig. 2 c & d show that part of Norwegian hydrogen exports is directly displaced by steel when steel exports are activated, constraining the amount of hydrogen available to Germany. In response, South German hydrogen demand reduces by reducing hydrogen-fired power production. However, German hydrogen and electricity prices remain just low enough to make local steel production more economical than imports. Overall, German steel prices increase by €28/ton when steel trade is activated, mainly due to the increase in hydrogen prices.

Hydrogen is predominantly generated using GSR and GSRH2 technologies in Norway and exported to Germany (Fig. 2 c & d). Although Germany still produces its own steel when steel trade is allowed, Norwegian exports to the global market increase system-wide steel output by 71 Mton/year. As a result, steel prices increase to match with the global steel price and, through the additional energy demand, prices for electricity and hydrogen also increase (Fig. 2 e & f). This increase is small for electricity (4%) with just more of the same supply technologies (mainly wind in Norway) being built. For hydrogen, the price increase is more substantial (24%) because hydrogen demand exceeds the maximum that can be supplied from Norwegian natural gas, requiring

Table 2
Description of the numbering in Fig. 1.

#	Name	Description
1	VRE transmission	Given the spatial variability of wind, solar, and water, additional transmission is needed to bring these resources to demand centres. Co-location of electrolysers with these resources can replace some of this transmission with cheaper hydrogen pipelines.
2	Offshore wind transmission	Offshore wind involves significant transmission costs to bring power to land and to transmit this power to demand centres. The co-location benefits of electrolysers mentioned above are implemented in a generic manner, thus applying also to offshore wind.
3	Electricity, hydrogen, and CO_2 links	Norway is connected to North Germany which is connected to South Germany. These transmission links can transport electricity, hydrogen, and CO_2 in either direction for use both as net imports/exports and as VRE balancing.
4	CO_2 transport and storage	CO_2 storage is only assumed feasible in Norway with costs involved in pipelines and storage wells. Germany can transport CO_2 to Norway for storage via the links mentioned in #3 above.
5	Connections to offshore salt caverns	Both Norway and Northern Germany have access to cheap salt cavern hydrogen storage (Caglayan et al., 2020). Given the location-specific nature of this resource, additional hydrogen transmission costs are involved in exploiting it.
6	Natural gas production	Norway can produce natural gas at a maximum rate imposed in the model, accounting for long-term production rate declines.
7	Natural gas imports/ exports	Norway can choose to export its natural gas directly at a specified production cost plus profit. Germany can import any amount of natural gas from the international market at a cost equal to the sum of Norwegian production costs, profits, and pipeline costs.
8	Clean ammonia imports	Germany can import clean ammonia from the international market for local reconversion to hydrogen.
9	Steel imports/exports	Norway can export steel at a specified international market export price. Germany can import steel at the specified export price plus the cost of shipping and loading.

Table 3
Total energy and steel demand and natural gas production in the three modelled regions (TWh/year). "Electricity" is modelled using an historical hourly profile, whereas "extra electricity" from additional electrification is modelled as constant load. Hydrogen and steel demand is also modelled as constant in all hours of the year.

	Norway	North Germany	South Germany
Electricity	134.9	166.3	332.5
Extra electricity	49.0	120.9	241.8
Hydrogen	21.0	51.8	103.6
Steel (Mton/year)		13.3	26.7
Natural gas production	600		

Table 4
Assumptions related to imports, exports, CO_2 taxation, and discount rate.

Natural gas production cost in Norway	2 €/GJ
Natural gas profits for exports	2 €/GJ
Natural gas pipeline cost to Germany	31.5 €/kW/year
Steel export value at the Norwegian border	450 €/ton
Steel shipping cost for imports to Germany	20 €/ton
Additional steel transport to South Germany	10 €/ton
Clean ammonia import price	126 €/MWh
CO_2 price	250 €/ton
Discount rate	5%

more expensive green hydrogen production in North Germany (Fig. 2d). The cost of green hydrogen increases rapidly with the scale of production due to the limited availability of excess electricity at low or negligible prices, thus driving up the hydrogen prices needed to bring extra hydrogen production into the market.

From the viewpoint of exporters, creating a supply-constrained blue hydrogen market that demands additional green hydrogen production to lift prices is vital for high profitability. The possibility to access large global markets through exporting IBPs like steel is an important avenue for achieving this aim. In this case, for example, the 24% increase in hydrogen prices from activating steel trade boosts the effective export profit on natural gas by €2.7/GJ, worth €5.8 billion per year for Norway.

For additional insight into the model behaviour, Fig. 3 shows a 2-week sample of hourly electricity generation data for the three modelled regions in the scenario with steel trade. Aside from reflecting the aggregated electricity generation data from Fig. 2b, Fig. 3 gives some interesting insight into how wind and solar are accommodated in the three regions. Norway uses hydropower and GSR power production when there is little wind and exports power to North Germany when there is excess wind. Power is also exported when German wind and solar output is low to limit the need for expensive hydrogen-fired power production. During times when electricity is very scarce, steel production also ramps down to avoid excessive electricity prices. South Germany has a high installed capacity of solar that causes large daily spikes in power output. These excesses are absorbed via pumped hydro and battery storage, electricity exports, and a small amount of electrolysis. Storage is discharged during the evenings, nights, and mornings, but most of the demand during these times is met via electricity imports. North Germany serves as a hub for power flows from Norway to South Germany, although it also occasionally relies on Norwegian electricity during times of low wind output. Some green H_2 is produced in North Germany when South German solar reaches very high levels. In effect, most green H_2 is produced from South German solar in North Germany to exploit local salt cavern storage.

4.2. Alternative policy scenarios

The previous section described baseline scenarios aligned with current political preferences. However, policy scenarios tilting more towards renewables and electrolysis (green) or natural gas and CCS (blue) are also possible. Fig. 4 compares the baseline scenarios without and with steel trade (discussed in the previous section) to green and blue scenarios without and with steel trade.

The green scenarios assume that Norway also avoids CCS in response to an EU-wide import ban on blue hydrogen (and IBPs produced from blue hydrogen). Natural gas exports to the world market are still allowed, although it is noted that Norway may need to shut down its natural gas production to fully comply with a green EU, losing €4.3 billion in export profits (equivalent to 1.2% of GDP) at the assumed export profit of €2/GJ (Table 4). Fig. 4a shows that the green scenarios require a substantial increase in electricity production to generate the required amount of green hydrogen. This includes a shift from hydrogen to natural gas due to much higher hydrogen prices (Fig. 4c). However, due to the VRE balancing services offered by green hydrogen production, hydrogen prices are similar to electricity prices despite the conversion losses and additional capital involved. The increase in unabated natural gas power production in these scenarios will require more negative-emission technologies installed elsewhere to ensure net-zero CO_2 emissions.

Steel trade mitigates these effects because it is more economical for Germany to import its steel instead of making it locally using green hydrogen. The steel premium in Fig. 4c shows that imports can save Germany €47/ton of steel (€1.9 billion per year). However, Fig. 4b shows that Norway does not produce any steel for export due to the higher cost of green hydrogen shown in Fig. 4c. Instead, Norway exports almost all its natural gas production directly, potentially leading to

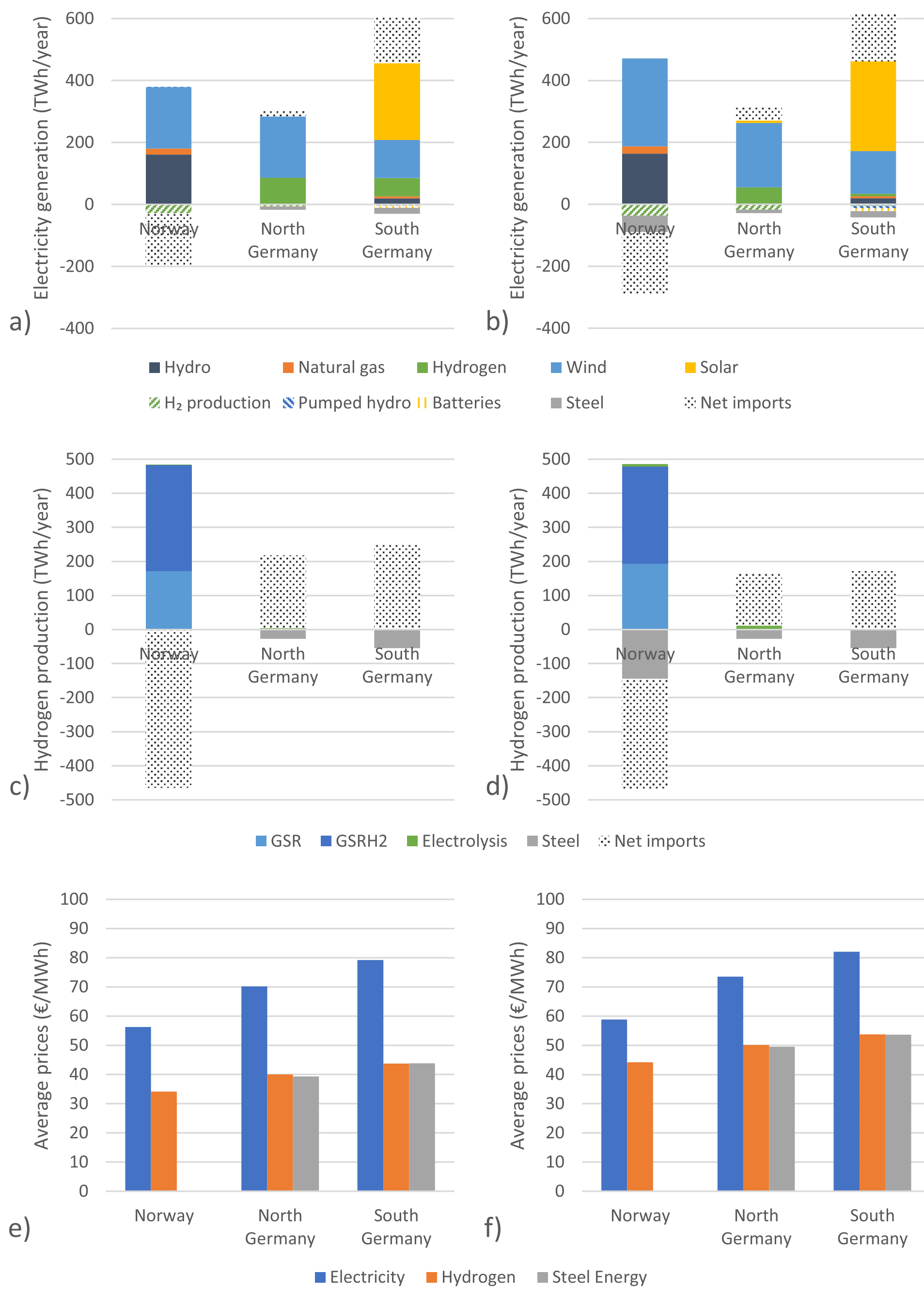

Fig. 2. Various results from the baseline scenario without (panels a, c, e) and with (panels b, d, f) steel trade. Steel exports in panels b and d are presented in energy-terms by accounting for 2.04 MWh of hydrogen and 0.75 MWh of electricity per ton of steel. Similarly, the Steel Energy price in panels e and f is calculated as the steel price (€/ton) minus steel production CAPEX and OPEX (levelized to €/ton) divided by 2.79 MWh/ton (combined hydrogen and electricity needed per ton of steel).

substantial CO_2 emissions from importers (dashed line in Fig. 4a). Hydrogen exports are also strongly reduced.

Norwegian system costs become positive in the green scenarios as energy export profits are no longer large enough to cancel out the costs of the energy system. The cost of avoiding CCS is greatest in the case with steel trade where CCS gives Norway access to attractive blue hydrogen profit margins (discussed in the previous section). Overall, avoiding CCS costs Norway 1.7% of GDP in the scenario with steel trade, but costs remain similar in the case without steel trade where blue hydrogen exports generate almost no additional profit. Costs for Germany are milder at 0.3% and 0.1% of GDP without and with steel trade, respectively.

The blue scenarios investigate permission to capture CO_2 in Germany and export these emissions to Norway for storage (Fig. 4b). In this case, GSR is also deployed in Germany for local power and blue hydrogen production, capturing CO_2 from the conversion of 584–593 TWh of natural gas to hydrogen and electricity. The steel premium in Fig. 4c is below zero, so Germany can produce its own steel below the market export value using locally produced blue hydrogen. Without steel trade, Germany can produce steel for €97/ton (€3.9 billion per year) less in the blue than the green scenario, mainly due to much lower hydrogen costs.

Trade flows change substantially when steel trade is allowed in the

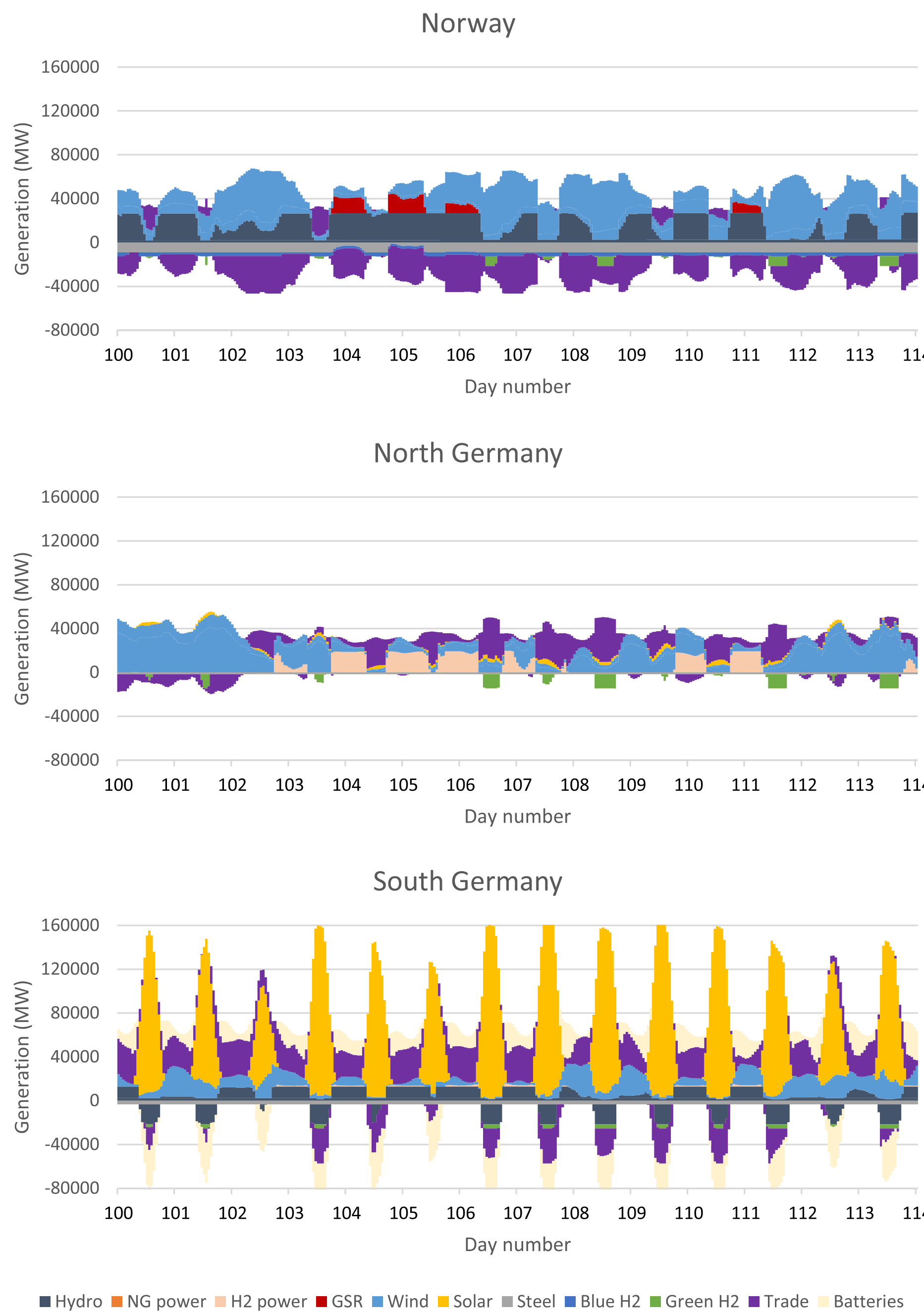

Fig. 3. Hourly electricity generation (negative numbers indicate consumption) in the three modelled regions over a two-week period (days 100–114 in the modelled year) for the scenario with steel trade.

blue scenarios (Fig. 4b). Without steel trade, Norway does not have an export market for blue hydrogen because Germany produces its own supply. However, steel trade allows Norway to utilize blue hydrogen together with green electricity to produce 231 Mton of steel for export, replacing almost all other energy exports. Fig. 4b shows that this shift to steel exports at the assumed export value of €450/ton allows Norway to gain 1.1% of GDP (€4 billion).

In comparison to the baseline scenarios, Norway loses 0–0.5% of GDP in the blue scenarios, whereas Germany gains 0.1–0.3% of GDP. For Norway, this further illustrates the benefit of securing a supply-constrained blue hydrogen market where importers need to rely on additional green hydrogen production. Germany avoids the large costs involved in supplying occasional large hydrogen fluxes to low-capacity-factor hydrogen-fired power plants by using the flexible GSR technology for power production instead. Added CO_2 transmission costs back to Norway are modest because GSR operates at a high capacity factor (thus producing a steady output of CO_2) by producing hydrogen for use in other sectors whenever electricity prices are low (Cloete and Hirth, 2020).

4.3. Key sensitivities

As the above results suggest, securing large demand for blue hydrogen is the key to long-term profitability for energy exporters like Norway. The most important uncertainties related to this demand creation are investigated in Fig. 5 for the baseline scenario with steel trade.

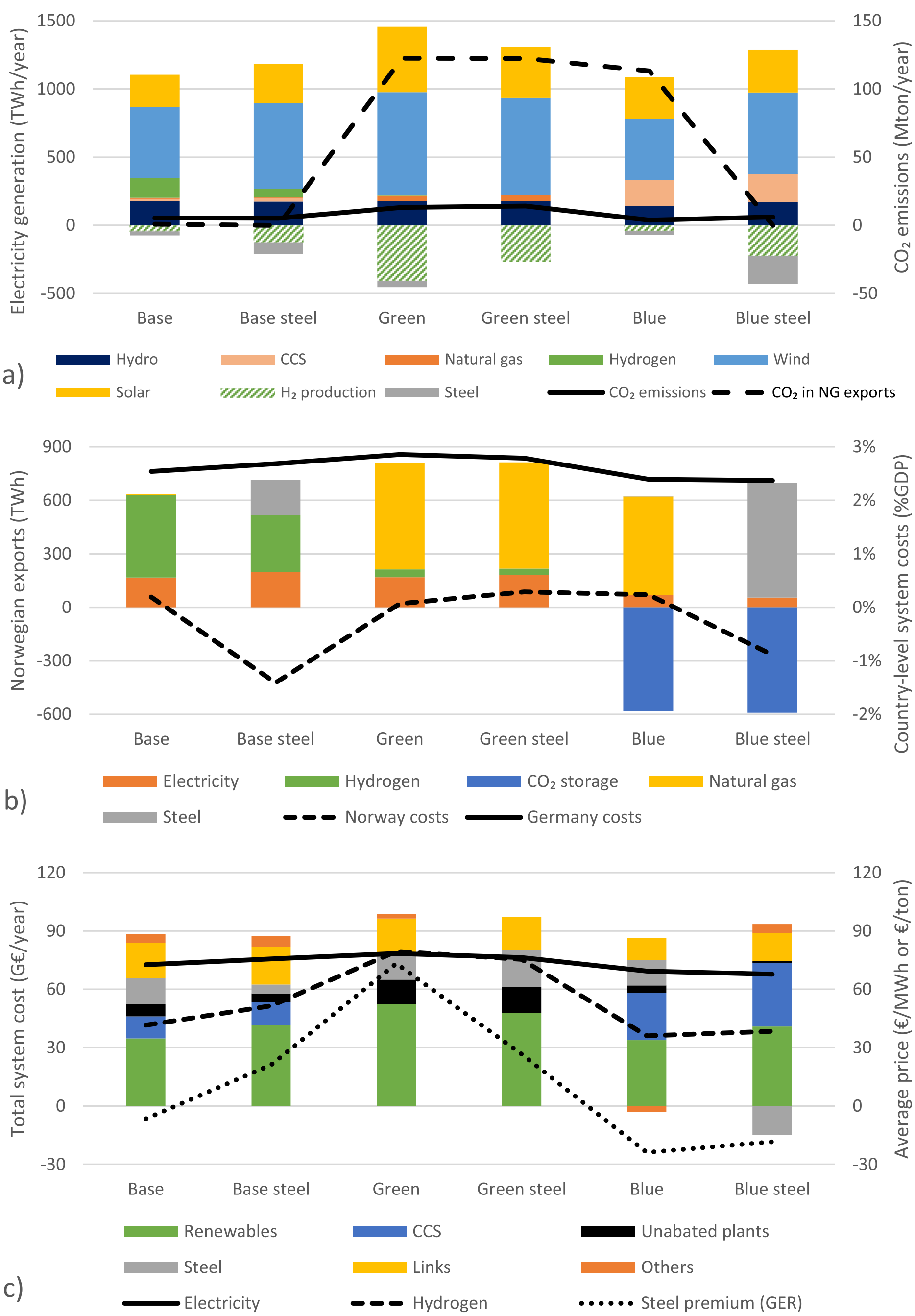

Fig. 4. Results from the assessment of different policy scenarios. Electricity generation, emissions, system costs, and commodity prices are aggregated across all three nodes. In panel a, CO_2 in NG exports refers to the CO_2 emissions potential of exported natural gas. In panel b, steel and CO_2 trade flows are presented in energy equivalents: 2.79 MWh of hydrogen and electricity per ton of steel and 4.87 MWh of combusted natural gas per ton of stored CO_2. In panel c, the steel premium is the difference between German steel prices and the assumed world export price of €450/ton and "Others" include electrolysers, batteries, pumped storage, hydrogen storage, and natural gas export profits.

Fig. 5a shows the impact of the two most direct hydrogen demand drivers: the size of the export market and the preference for hydrogen over electricity as a clean energy carrier. The total size of the export market (Fig. 5a, left) was changed by scaling all aspects of the German system by the appropriate factor in the simulation.

When hydrogen demand is low, Norway must rely on steel exports as a profitable export mechanism for its blue hydrogen. As hydrogen demand is increased, however, steel exports become less significant before disappearing completely. When Norwegian blue hydrogen exports reach their maximum at an export market size between 100% and 200% of German demand in Fig. 5a (left), further increases in hydrogen demand strongly increase hydrogen prices to bring more green hydrogen production to the market. These higher prices increase Norwegian profits by 2% of GDP (€7.1 billion) when the export market size increases from 100% to 400% of the German market. Fig. 5a (right) shows that an increase in the hydrogen share of extra energy demand in Germany is not enough to create such a supply-limited hydrogen market. However, if the export market is larger than only the German market, the preference for hydrogen relative to electricity would have a larger impact.

Hydrogen demand is also increased by higher CO_2 prices due to the competition between natural gas and hydrogen for thermal power production. Fig. 5b (left) illustrates this effect. At a CO_2 price of €100/ton, all thermal power is produced using natural gas and costs are low enough that Germany needs very little electricity imports from Norway. Germany does import some hydrogen, but most of Norway's energy exports take the form of steel that is exported to world markets. Natural gas still dominates at €150/MWh, but hydrogen takes a 91% share of thermal generation at a CO_2 price of €250/MWh and 96% at €350/ton.

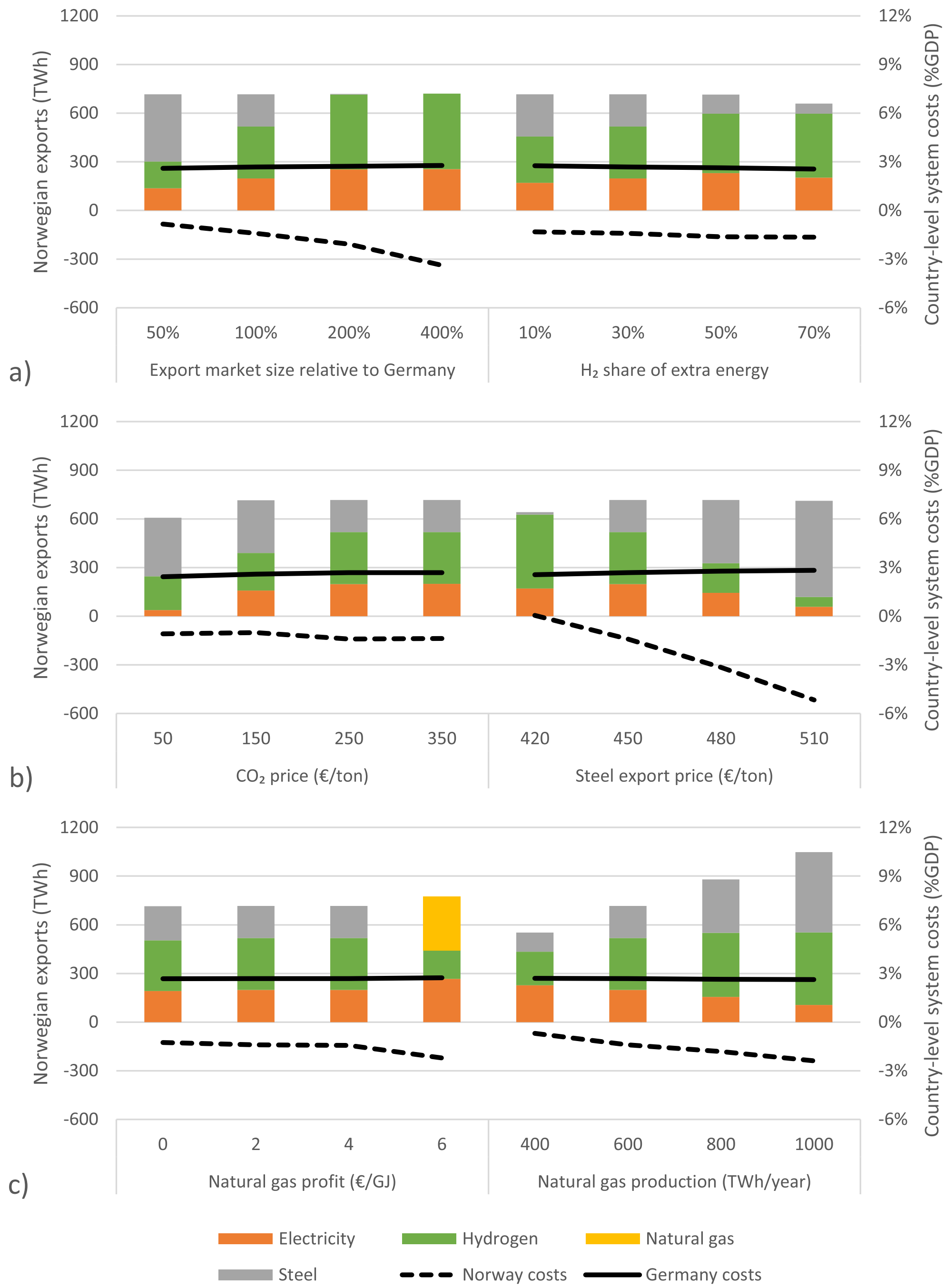

Fig. 5. Norwegian exports and country-level costs for various sensitivity scenarios. Norway exports electricity and hydrogen to Germany (limited demand), and steel and natural gas to the global market (unlimited demand). Steel trade flows are presented in energy equivalent terms: 2.79 MWh of hydrogen and electricity per ton of steel.

The small amount of unabated natural gas that remains even at these high CO_2 prices is testament to the high cost of hydrogen transmission and storage needed to supply thermal power plants with occasional large fuel fluxes for very-low-capacity-factor operation. These costs related to hydrogen supply are larger than those related to natural gas supply using the fixed cost for natural pipeline imports in Table 4.

The greatest benefit for Norway arises from higher steel prices, which could result from stricter international CO_2 regulations, causing an increase in global production costs. As Fig. 5b (right) illustrates, Norwegian profits increase by fully 5.2% of GDP (€18.8 billion) when prices rise from €420/ton to €510/ton. Rising steel prices also cause Norway to export less hydrogen, increasing the need for green hydrogen production in Germany at a cost of 0.3% of GDP (€9.4 billion). Put differently, an increase in steel prices by just 21% is enough for Norway to use most of its energy for domestic steel production, with little energy left for direct exports. For perspective, global steel production in 2019 was 1880 Mton, implying a maximum hydrogen and electricity demand of 5250 TWh. At the highest steel export price of €510/ton, Norwegian exports amount to 11% of this global potential. Unless Norway is the lowest-cost supplier, this may be an unrealistically high share of the global steel market, but other IBPs can also be produced to diversify these exports.

Fig. 5c (left) shows that natural gas profits must rise to €6/GJ for direct natural gas exports to become more profitable than producing blue hydrogen for making clean steel at an export value of €450/ton. At lower natural gas profits, natural gas costs in Germany also decline, leading to a little more natural gas power production, slightly reducing Norwegian hydrogen exports.

Finally, Fig. 5c (right) quantifies the higher profits that Norway can expect if it can maintain its natural gas production closer to present levels in the long-term. Revenues from higher sales volumes have a larger effect than the lower hydrogen prices created by a larger supply. Lower hydrogen prices cause Germany to import more hydrogen for power production instead of direct electricity imports. The figure also illustrates how steel exports absorb additional blue hydrogen output after the German hydrogen market is saturated.

4.4. Discussion of blue hydrogen demand drivers

It is informative to discuss the factors that may influence the levels of the four hydrogen demand drivers investigated in Fig. 5 a & b. On the one hand, the demand for Norwegian blue hydrogen is driven by (political and economic) competition from other clean energy alternatives: increased efficiency, higher levels of electrification, locally produced green or blue hydrogen, or blue hydrogen imports from other geographical areas (Fig. 5a). On the other hand, demand is driven by the demand for hydrogen from various emerging applications (Fig. 5b).

On the competitiveness of Norwegian blue hydrogen versus local production, results from the present study show that blue hydrogen imports can satisfy large-scale German demand for about half the cost of local green hydrogen.[6] However, low-volume production of green hydrogen from wind and solar energy that would otherwise be curtailed is possible at low prices as shown in the baseline scenario (North Germany in Fig. 2d). Given this economic advantage, political preferences represent the primary uncertainty for Norwegian blue hydrogen export demand. Two edge cases are of particular concern: 1) North Europe produces most of its own blue hydrogen from imported natural gas (or local biomass) and 2) North Europe bans the import of fossil hydrogen. The intermediate scenario modelled in the present study where European countries participate in a technology-neutral clean hydrogen market and importers avoid local CCS offers an attractive middle ground, but these edge cases could materialize in certain countries. For instance, the German national hydrogen strategy focuses on green hydrogen, although the possibility for participating in a technology-neutral European hydrogen market is left open (BMWi, 2021). On the other hand, large blue hydrogen projects are being planned in the UK[7] and the Netherlands.[8]

The demand for hydrogen in general will depend on its practical, political, and economic attractiveness relative to other clean energy options. For example, the German demand levels in Table 3 represent a strong focus on efficiency and electrification, with hydrogen generally reserved for sectors where it is the only viable option (next to substantial amounts of biomass and imported green synfuels). The currently unproven hydrogen economy must be successfully demonstrated to claim higher market shares relative to these competitors, potentially aided by the lower costs of Norwegian blue hydrogen.

In addition, Norway may face significant market competition from Russian blue hydrogen pipeline imports. However, Norway's geographical proximity to North Europe will give it a sizable advantage. For example, Russian hydrogen will need to travel about 3000 km further than Norwegian hydrogen, implying a large transmission cost differential of €28/MWh using a capacity factor of 80% under the H_2 transmission cost assumptions employed in this study. The vast scale of Russian gas pipelines may reduce this cost differential, but it will still support Norwegian hydrogen export profits.

Regarding the demand for hydrogen from specific sectors, power production is one important application. Thermal power plants will remain necessary to meet demand during extended periods of low wind and sun, and hydrogen is the leading zero-carbon option. However, it should be noted that the case with a €150/ton CO_2 price already cuts German emissions by about 95% relative to 1990 levels (although additional emissions may arise from sectors such as aviation). Increasing the CO_2 price to €250/ton (the baseline scenario) to encourage more H_2-fired power production cuts emissions by an additional 90%, but negative emission technologies may be a more economical solution for avoiding this final fraction of CO_2.

Another potentially large source of demand comes from blue hydrogen use in industry. Because IBPs can be traded easily, global markets should be considered. For the example of steel, global demand in 2019 was 1880 Mton, representing potential demand for up to 4000 TWh of hydrogen. The chemicals sector and other processes demanding high-grade heat or carbon-free reducing agents substantially increase this potential.

In a low-carbon world, the H_2-DRI technology considered in this study will compete with several other low-carbon steelmaking pathways. For natural gas-based processes, DRI can be produced with syngas as reductant with CO_2 capture employed after the ore reduction. Alternatively, the methane can be reformed to hydrogen, using a dedicated steam methane reforming process with CO_2 capture, which can then be used as reductant, as with the blue H_2-DRI process considered in this study. Advanced blue hydrogen technologies can substantially improve the competitiveness of both these natural gas-based clean steelmaking routes (see the Blue Optimistic scenario in Fig. S2 in the Supplementary Material). Applying CCS to coal-fuelled production pathways can also significantly reduce CO_2 emissions, keeping these processes competitive in a future scenario with high carbon taxes. When applying high CO_2 prices to the steelmaking process routes reviewed by Kuramochi et al. (2012),[9] it becomes clear that the conventional blast furnace route will not be competitive in a net-zero world, even with CO_2 capture. However, smelting reduction processes like COREX and HIsarna (Meijer et al., 2013) could produce low-carbon steel in the cost range of 426–543 €/ton, which is comparable to the steel prices assumed in Fig. 5b. It can be noted that, aside from cost-competitiveness, deployment of these coal-fuelled technologies in developing regions may be constrained by proximity to large CO_2 storage reservoirs. Further details regarding these calculations and clean steel competition are included in the Supplementary Material (Fig. S3).

Another important uncertainty regarding IBP exports is whether importers will be willing to scale down uncompetitive heavy industry. Industrial lobbies wield significant political power and could win subsidization to keep uncompetitive actors operational. The large industrial infrastructure transition required for reaching net-zero presents an important decision point for importers in this respect.

[6] The levelized cost of blue hydrogen production with the GSRH2 technology in Norway and transmission to Germany is €41/MWh when natural gas can be exported at a profit margin of €2/GJ and €33/MWh without natural gas profits. In contrast, the green scenario without steel trade in Fig. 3 returns a German hydrogen price of €80/MWh. Elevated hydrogen prices set by green hydrogen increase Norwegian profits.

[7] H2H Saltend (https://bit.ly/3vKvZZW) and BP Teesside (https://on.bp.com/37NFfo3).

[8] H-vision (https://www.h-vision.nl/en).

[9] The cited study finds that the cost of steel production using the conventional integrated steelmaking process with blast furnaces is 472 €/ton hot rolled steel (after adjusting for a 40 €/ton CO_2 tax), which is close to the current export price of 450 €/ton considered here. Therefore, the costs from the cited study can be reasonably compared to the production costs in this study after adding a comparable CO_2 tax.

4.5. Applicability to other importers and exporters

The present study was based on Norway and Germany as the large amount of input data required is readily available and effective energy trade is a high priority to both countries. Although it is not possible to model the entire world market in this level of detail, several key findings from this study can safely be generalized to other (far larger) energy exporters and importers.

From the perspective of exporters, it is important to highlight that most players (e.g., OPEC+) are much more vulnerable to revenue-risks from global decarbonization than Norway, which is often ranked the world's most developed country[10] and controls a growing sovereign wealth fund[11] currently valued at approximately 400% of GDP. Indeed, securing long-term export revenues from their vast remaining oil and gas reserves is key to socio-political stability in the world's largest energy exporting regions.

The viability of electricity and hydrogen exports is dependent on the proximity between importers and exporters and regional energy policy, thereby requiring dedicated studies for each individual exporter. IBPs, on the other hand, are globally tradable commodities like oil, and can therefore be reasonably represented as a price-inelastic world market as was done in this work. With most of the world still developing, demand for these easily tradeable commodities will likely remain robust in the longer-term future. Thus, the potential to export clean energy in the form of locally produced commodities like metals, chemicals (including potential fuels like ammonia and methanol), ceramics, and cement offers an effective hedge against risks from declining oil & gas demand next to region-specific opportunities for direct electricity and hydrogen exports. The key uncertainty in this respect is the degree to which both exporters and importers will embrace this model of heavy industry relocation.

From the viewpoint of energy importers, large developing markets in Asia (mainly China, India, and ASEAN), home to about half the global population, can benefit even more than Germany from reliable and affordable clean energy imports. Developing Asia is very densely populated, posing challenges related to the land requirements of variable renewables and the associated transmission network expansion. The region also has a poor wind resource[12] and only an average solar resource.[13] Compared to developed Europe, large developing economies have a far greater demand for IBPs for constructing the wide array of infrastructure required to economically uplift their citizens. Furthermore, such a large demand for non-energy-related investment will make it even more challenging to mobilize the capital required to expand complex and capital-intensive local clean energy systems at a pace compatible with 1.5–2 °C pathways. If a large part of the required energy-related investment is instead left to exporters, the global decarbonization effort can be accelerated significantly while minimizing competition with non-energy-related investments required for economic upliftment.

Thus, the world's largest energy exporters and importers can establish a similar mutually beneficial clean energy trade relationship as simulated between Norway and Germany in this work. Direct trade of electricity and hydrogen should be investigated on a case-by-case basis, but the relocation of heavy industry to facilitate trade in IBPs appears to be a generally attractive strategy.

5. Conclusions

The global energy transition introduces substantial risks and uncertainties for many actors, not least fossil fuel exporters. In this study, optimized energy deployment and trade strategies between a hydrocarbon exporter (Norway) and a major energy consumer (Germany) were simulated using a coupled electricity-hydrogen-steel energy systems model, yielding insights that are also applicable to other major energy exporters and importers. Steel is viewed as an example of an easy-to-export industrial base product (IBP) that can substitute natural gas, hydrogen, or power trade.

The primary conclusion is that both importers and exporters stand to benefit from a coordinated decarbonization effort. Exporters can profit from the energy transition if they successfully adapt by replacing their carbon exports by clean energy carriers, mainly blue hydrogen and climate-neutral IBPs such as steel. Importers also stand to benefit from lower hydrogen prices, avoidance of local CCS, and reduced dependence on onshore wind to avoid challenges with public acceptance and land scarcity.

Export profitability is driven by elevated hydrogen prices in importing regions that otherwise must rely on more expensive, locally produced green hydrogen. Given the challenges with hydrogen exports over long distances, energy exporters like Norway that are geographically located close to a large energy importing region stand to gain most from this dynamic. However, several uncertain factors will determine future blue hydrogen demand and profitability, including the number of links to countries willing to import blue hydrogen and the attractiveness of hydrogen relative to other decarbonization pathways such as efficiency, electrification, and biomass across a broad range of applications.

Exporters can also deliver low-carbon energy to the broader world market via clean IBPs. These products are highly suited to international trade, not only because they are cost-effective to export by ship over long distances but also because they are easy and cheap to stockpile, thus offering high supply security for importers. This pathway is especially relevant to exporters lacking proximity to a large import market accessible via hydrogen pipelines and HVDC transmission. It can also hedge well-connected exporters like Norway against the risk that the hydrogen export market is much smaller than expected – a scenario that may arise in the edge cases of large-scale CCS adoption by importers or an import ban on fossil-derived hydrogen. If regional blue hydrogen demand proves robust, however, additional demand created by production of IBPs for the international market will boost local hydrogen prices, shifting some of the benefit from importers to exporters.

Exporters can initiate this clean energy trade strategy via policy commitments to ramp down carbon exports. For example, current policy momentum in the EU is towards an early phase-out of natural gas and it is up to natural gas exporters to present a value proposition that is attractive enough to secure a long-term and profitable export market. For example, Norway can commit to ramp down all carbon exports linearly to reach zero by 2040. This will 1) stimulate local actors to expand CCS infrastructure and construct clean industries for decarbonizing energy exports and 2) signal to energy importers that increasing supplies of affordable, practical, and secure blue hydrogen and clean IBPs will be available on the global market to simplify the energy transition.

CRediT authorship contribution statement

Schalk Cloete: Conceptualization, Methodology, Formal analysis, Investigation, Writing – original draft, Funding acquisition. **Oliver Ruhnau:** Conceptualization, Methodology, Investigation, Writing – original draft. **Jan Hendrik Cloete:** Investigation, Writing – original draft, Writing – review & editing. **Lion Hirth:** Conceptualization, Methodology, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence

[10] https://hdr.undp.org/en/content/latest-human-development-index-ranking.

[11] https://www.nbim.no/.

[12] https://globalwindatlas.info/.

[13] https://globalsolaratlas.info/map.

the work reported in this paper.

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Appendix A. Supplementary data

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