ENERGY-INTENSIVE INDUSTRY AS A PRACTICAL AND COST-EFFECTIVE VECTOR FOR BLUE HYDROGEN EXPORTS – A NORWEGIAN CASE STUDY

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Abstract

As political will gathers behind the ideal of rapid decarbonization, the future looks increasingly dim for oil & gas exporters. CCS offers a pathway for continued operation in the longer-term as the world decarbonizes, but this is not a straightforward solution. Many oil & gas importers are opposed to CCS and are instead looking to replace oil & gas imports with greener alternatives. The alternative solution of converting cheap locally produced hydrocarbons to hydrogen and electricity with CCS substantially increases the cost and complexity of energy exports. This study explores an alternative solution: local utilization of clean hydrogen from natural gas to produce energy intensive industrial products like steel. Such products are much easier to export than hydrogen or electricity. The system-scale modelling assessment presented in this study shows that the energy costs of clean steel using blue hydrogen in Norway is 174 €/ton cheaper than when it is produced using green hydrogen in Germany. This difference amounts to about a third of total steel production costs, giving oil & gas exporters like Norway a large competitive advantage.

Keywords: *CO_2 capture and storage, Hydrogen, Energy system modeling, Oil & gas, Energy-intensive industry*

1. Introduction

The future of oil and gas exporting regions appears highly uncertain. Momentum is building behind the vision of carbon neutrality by mid-century, with Europe leading the way in terms of ambition. The ongoing COVID-19 pandemic appears only to have strengthened this resolve, despite the economic impact.

As a result, the International Energy Agency's World Energy Outlook report [1] paints a bleak future for oil & gas producers. Relative to pre-pandemic estimates, the net-present value of all oil and gas production up to 2040 is cut in half in the Sustainable Development Scenario, which still falls well short of carbon-neutrality by 2050.

Clearly, the oil & gas industry requires a fundamental re-evaluation of its longer-term role in a decarbonizing world. CO_2 capture and storage (CCS) must play a central role in any such strategy (and in the broader global decarbonization effort [2]). There is a great deal of technology transfer possibilities between oil & gas extraction and distribution and CO_2 transport and storage. In addition, CO_2 enhanced oil (or gas) recovery can increase the profitability of such synergies. In a European context, these issues are of high relevance to Norway, which possesses much of the continent's oil & gas reserves and CO_2 storage potential.

However, a key challenge with such a strategy is that the clean energy products resulting from local CCS, mainly hydrogen and electricity, are much harder to export to the international market than oil & gas [3]. Hydrogen has a volumetric energy density less than a third that of natural gas and liquifies at considerably lower temperatures, making it inconvenient for exports. Electricity exports are even more costly and, given the challenge of longer-term electricity storage, no country will be willing to build up a large electricity import dependence.

A much more practically and economically attractive alternative is to convert locally produced clean hydrogen and electricity into energy-intensive industrial products (e.g., metals, cement, chemicals), which are much simpler to export. In addition, it can be argued that such a value-added approach to using local energy resources will produce more local value in terms of jobs, skills, and local technology development. However, despite the apparent benefits of such an approach, prominent Norwegian roadmaps, such as the Norwegian Hydrogen Strategy [4] and the Energy Transition Norway 2020 forecast from DNV GL [5], place a much larger emphasis on blue hydrogen and electricity (from hydro- and wind power) exports to Europe, than on local usage to produce energy-intensive industrial products for export.

This study therefore presents a system-level assessment of the economic benefits of using energy-intensive industrial products as a Norwegian energy export vector. Specifically, clean steel production is considered as an example and the energy costs for production in Norway and Germany are compared.

2. Methodology

The study is conducted based on a previously published model of an integrated electricity and hydrogen system in Germany [6]. The model optimizes investment and hourly dispatch of a range of electricity and hydrogen generation, transmission, and storage infrastructure to minimize total system costs (including a price on CO_2). The model is solved using the General Algebraic Modelling System (GAMS) software.

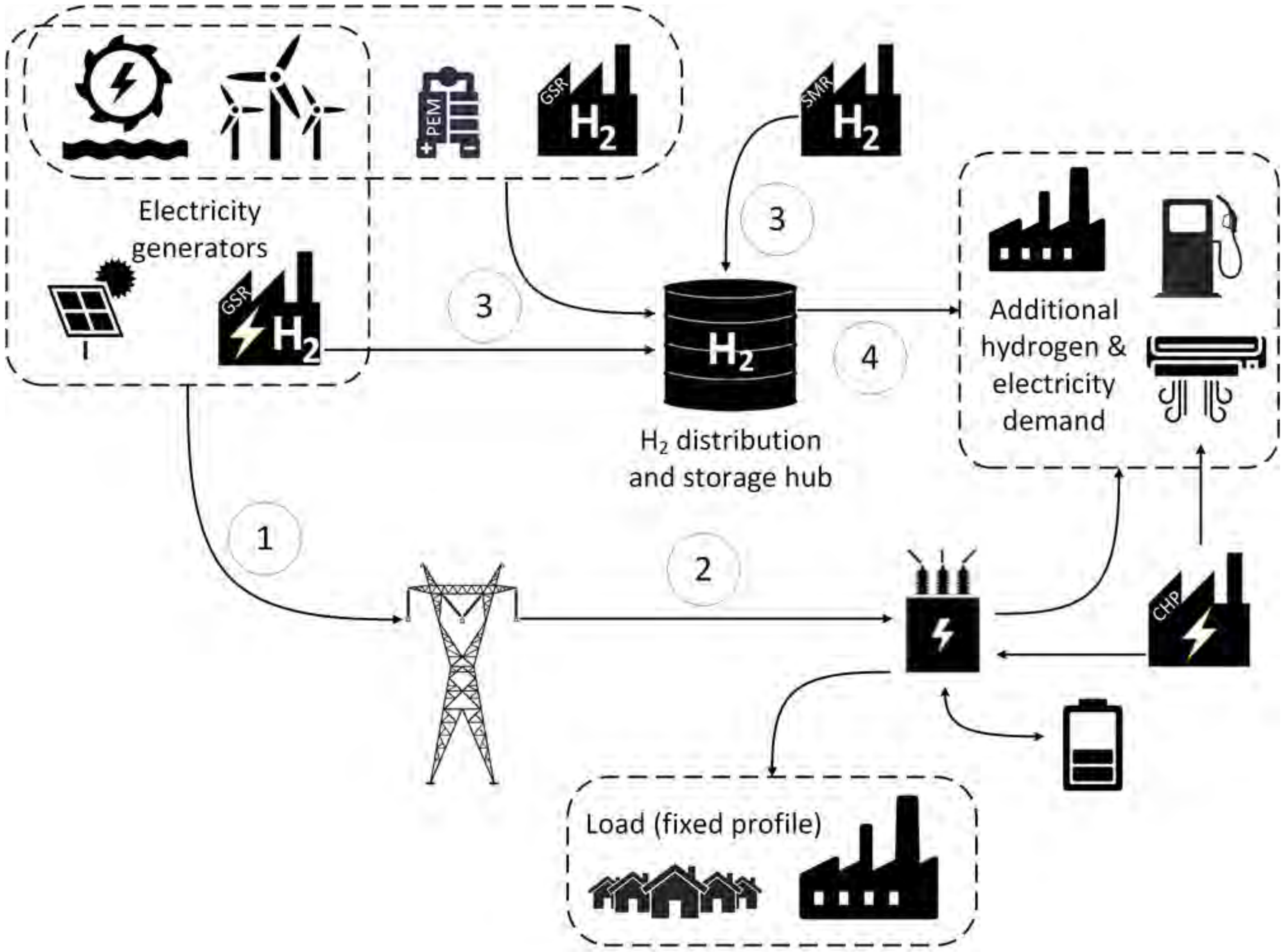

Figure 1: A schematic of the modelled energy system for Norway. The different types of transmission are indicated by numbers: 1) added transmission for wind, solar, and hydro due to their spatial mismatch with demand centers, 2) conventional transmission proportional to peak system electricity demand, 3) hydrogen transmission pipelines from various producers to central storage and distribution hubs, and 4) hydrogen distribution to serve a flat hydrogen demand profile.

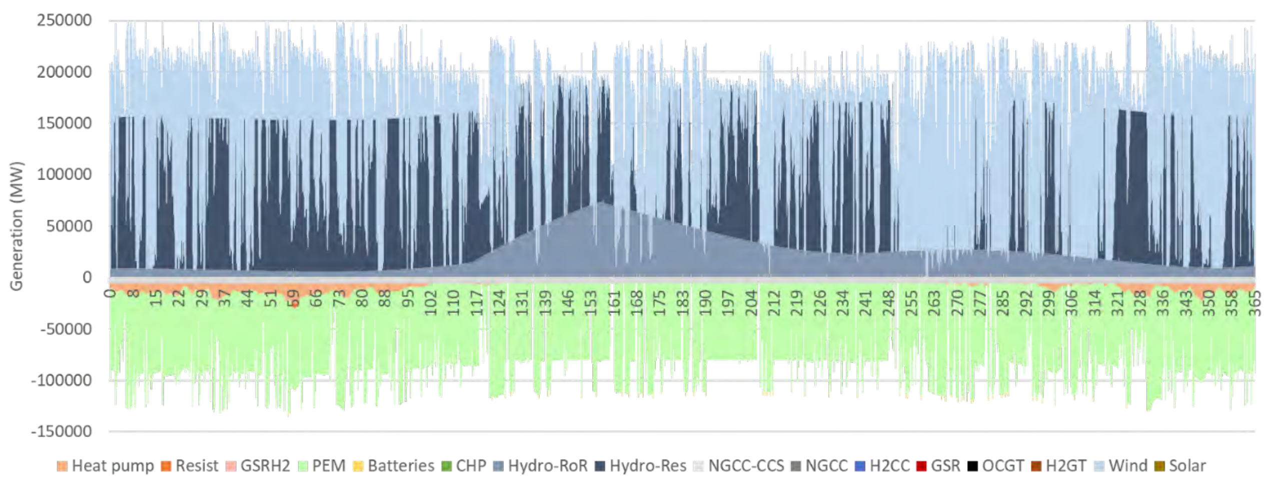

Figure 2: An example of the hourly electricity generation profile in Norway for a green hydrogen scenario (CCS technologies not allowed). Consumption from electrolysis and heat pumps is also shown. The x-axis indicates the days in the year.

2.1 System description

In the present work, this model was extended for optimizing the long-term (2040) Norwegian energy system. Aside from adopting appropriate hourly load and renewable energy availability profiles for Norway from the Open Power System Database [7] and the Renewables Ninja database [8], the following important modifications were made relative to the aforementioned study [6] based on Germany:

1. Hydropower was included, accounting both for run-of-the-river and reservoir hydro.
2. Offshore wind was preferred due to the large public resistance to onshore wind in Norway.
3. A heat balance was incorporated to separate energy demands for heating applications from electricity demand.

The simulated Norwegian energy system is summarized in Figure 1. A constraint was imposed that all electricity must be generated via renewable sources while natural gas can be used for generating hydrogen with CCS (blue hydrogen). An additional transmission cost of 200-300 €/kW was imposed for hydro, wind, and solar power due to their location dependence that does not align perfectly with demand. To minimize this cost, it was assumed that electrolyzers (green hydrogen) and gas switching reforming (GSR) [9, 10] technology (blue hydrogen) that also consumes some electricity are co-located with the location specific renewable electricity generators. Thus, the large electricity demand from these consumers does not need to be transmitted over long distances, instead requiring cheaper hydrogen transmission to demand centers, saving significant system costs.

The electricity not consumed for hydrogen production on site is transmitted to two different demand centers: a load profile that varies by hour (representing existing residential, commercial, and industrial demand) and an additional constant load profile representing future additional demand for clean energy to decarbonize areas that are currently not electrified (like transportation and additional energy-intensive industry for exports). This second demand center is subject to large uncertainty, both in its overall magnitude and in the split between electricity and hydrogen. It will therefore be subject to a sensitivity analysis in this study. Battery storage can also be deployed to help balance supply and demand.

In addition, the model optimizes a separate energy balance for heating. Currently, most of Norway's heating is done using simple resistance heating, which is a very inefficient use of its valuable clean hydropower resource. It also creates large seasonal variations with much more electricity demand in winter, leading to an oversized electricity transmission and distribution network that is poorly utilized in summer months. Hence, the model also includes the possibility of heat pumps and biomass combined heat and power (CHP) plants with CCS as options for satisfying the heating demand during winter months. The coefficient of performance of the heat pumps are adjusted according to the population-weighted ambient temperature profiles of Norway's three largest cities to reflect the decline in heat pump performance on colder days. The CHP plant is equipped with a variant of the swing adsorption reactor cluster (SARC) CO_2 capture technology [11, 12] that is capable of running on electricity in winter months and heat in summer months to ensure that these plants can supply maximal heat output when it is most needed.

Figure 2 shows a typical output from the model for a scenario where no CCS technologies are allowed. The seasonal availability of run-of-the-river hydropower (Hydro-RoR) is clearly visible in the electricity supply profiles. During spring when the snow melts, a large amount of electricity is generated, peaking in early summer before settling at a lower constant generation until freezing takes place at the start of winter. During winter months, run-of-the-river generation is minimal. Of much greater value to the energy system is reservoir hydropower (Hydro-Res) that can be ramped up and down depending on system needs due to the large reservoirs that store potential energy for on-demand deployment. In this example, it can clearly be seen how reservoir hydro is used to balance the fluctuating output of wind power.

Table 1: Selected technology cost and performance assumptions. The type of energy by which the capital costs are scaled is given in brackets.

Technology	Capital cost (€/kW)	Lifetime (years) Fixed O&M (%/year)	Performance
Run-of-the-river hydro	1370 (electric)	40 2%	Capacity factor: 33% Maximum generation: 55 TWh/year
Reservoir hydro	1560 (electric)	40 2%	Maximum reservoir storage level: 50 TWh Annual inflow: 108 TWh/year
Offshore wind	1655 (electric)	25 2.8%	Capacity factor: 55%
Dedicated GSR H_2 plant	862 (H_2)	40 3%	Efficiency: 86.8% H_2 (LHV), -5.4% electric
CHP CCS	1500 (winter heat)	40 3%	Efficiency winter/summer: 75%/30% heat and 13%/18% electric
Heat pump	411 (electric)	20 2%	Coefficient of performance: ~3 during winter

The large electricity consumption of electrolyzers (PEM) is also clearly visible in Figure 2. Electrolyzers also contribute to balancing fluctuating wind power, although to a lower extent than reservoir hydro. The model prefers to run electrolyzers at a higher capacity factor to reduce their levelized capital costs and to reduce the costs related to transmitting and storing large fluxes of intermittently produced hydrogen. Finally, significant electricity consumption from heat pumps can also be identified during winter months. This consumption fluctuates significantly depending on the ambient temperature.

Cost and performance assumptions are based on the year 2040 and the technologies not included in the previous study on the German system [6] are detailed in Table 1. It should also be mentioned that natural gas prices of 4 and 6 €/GJ are assumed for Norway and Germany, respectively, to reflect the added costs involved in transporting natural gas to Germany. A CO_2 price of 100 €/ton is used in this study.

2.2 Scenario and case definitions

Two scenarios are investigated:

1. Green H_2: In this scenario no CCS is allowed and all hydrogen must be produced via electrolysis.
2. Blue H_2: In this case, CCS is allowed to compete with electrolysis.

Both scenarios are completed for Norway, using the setup described in section 2.1, and for Germany, using a similar setup as in our previous study [6]. Additional constraints are imposed to maximize renewable electricity generation, enforcing Norwegian and German power production to be at least 100% and 70% renewable, respectively.

It is assumed that in a future energy system, both countries will experience a substantial increase in clean energy demand (in the form of renewable electricity and hydrogen) to power the transport and industrial sectors. Therefore, in each scenario, eight different cases are simulated to investigate uncertainties associated with this additional demand:

- 4 different levels of increased total demand with a 50/50 split between electricity and hydrogen: 100, 200, 300, and 400 TWh/year.
- 4 different H_2/electricity splits at 300 TWh/year of additional demand with 20%, 40%, 60%, and 80% H_2 share.

3. Results and discussion

Results will be presented and discussed in three sections: Norway, Germany, and the implications for steelmaking using the HYBRIT process.

3.1 Norway

The cost-optimal generation mixes for the 8 different cases in the two different scenarios are illustrated in Figure 3. For the Green H_2 scenario, an increase in clean energy demand strongly increases the demand for electricity, both due to direct demand for clean electricity and due to electricity demand from electrolyzers. As more electricity is demanded, the share of wind power strongly increases, while hydropower is constrained to a maximum according to Table 1. In the case with the lowest additional energy demand, the model chooses to deploy offshore wind instead of run-of-the-river hydro, which only runs in the summer when demand is lowest.

The increase in clean energy demand in the Blue H_2 scenario is much milder because all hydrogen demand is met through natural gas reforming using the GSR technology. A small amount of additional generation from biomass CHP plants is also visible. These plants are the reasons for the negative CO_2 emissions intensity in these cases.

When considering the cases with different shares of hydrogen in the clean energy mix, total electricity demand increases with hydrogen share in the Green scenario (due to greater electrolyzer losses) and decreases in the Blue scenario (due to more clean energy being supplied by blue hydrogen instead of electricity).

Figure 4 shows the minimum system costs achievable in each case. Increases in clean energy demand naturally increase the total system cost, but also the levelized energy cost. This increase is mainly due to the limitation on reservoir hydro, which is highly economical but limited in available capacity. As offshore wind must produce an ever-increasing share of electricity, the average energy cost goes up. This trend is less severe in the Blue H_2 scenario because of the smaller reliance on offshore wind.

When increasing the share of hydrogen, the Green scenario becomes gradually more expensive, whereas the Blue scenario becomes cheaper. This is because green hydrogen must be more expensive than the electricity used to produce it, whereas blue hydrogen from natural gas costing 4 €/GJ is attractively cheap. Overall, the Blue H_2 scenario is considerably cheaper than the Green H_2 scenario, especially when greater shares of hydrogen are required.

Finally, Figure 5 breaks down the cost components not shown in Figure 4. In the Green scenario, greater electricity demand increases the added VRE (variable renewable energy) transmission and regular transmission costs. More hydrogen demand naturally increases electrolyzer costs, while hydrogen storage costs also increase substantially as electrolyzers need to play an increasingly important balancing role, producing more intermittent hydrogen outputs.

Hydrogen storage costs are absent in the Blue scenario because hydrogen is produced at steady state. Grid related costs are also lower due to the smaller deployment of offshore wind power.

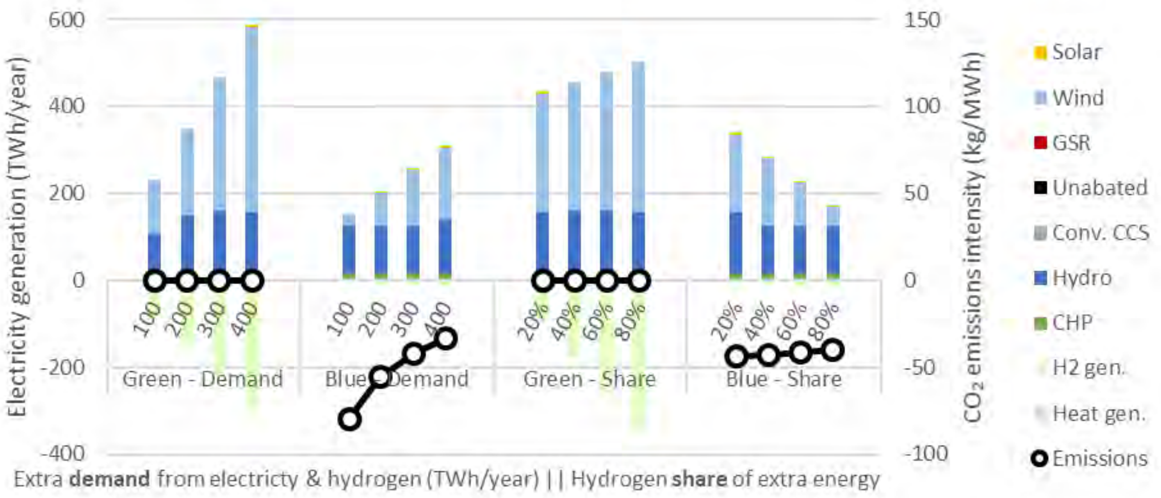

Figure 3: Breakdown of electricity generation and emissions intensity for all cases in Norway.

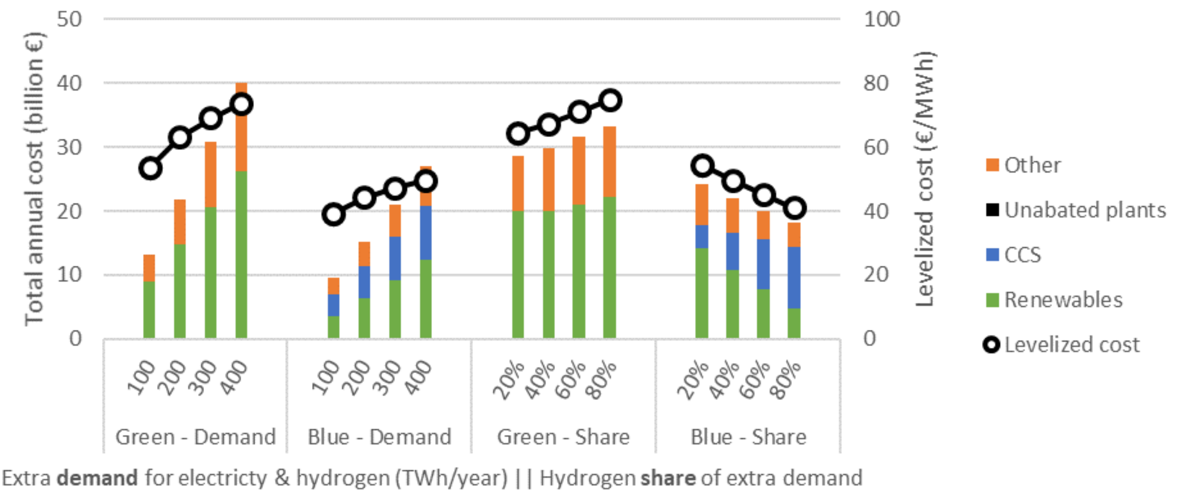

Figure 4: Breakdown of costs for all cases in Norway. Levelized costs lump together electricity, hydrogen, and heat.

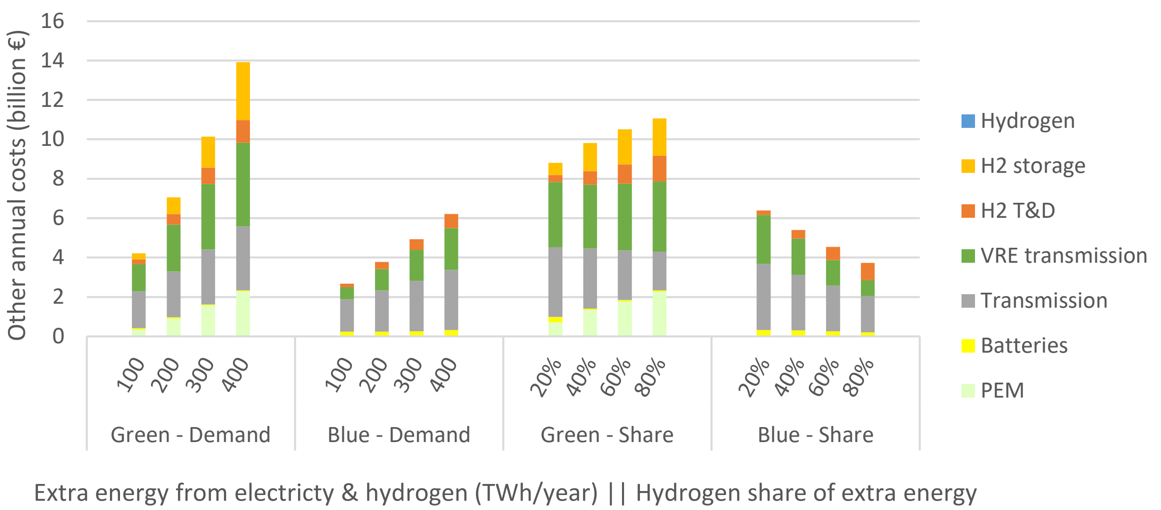

Figure 5: Breakdown of the "Other" costs in Figure 4.

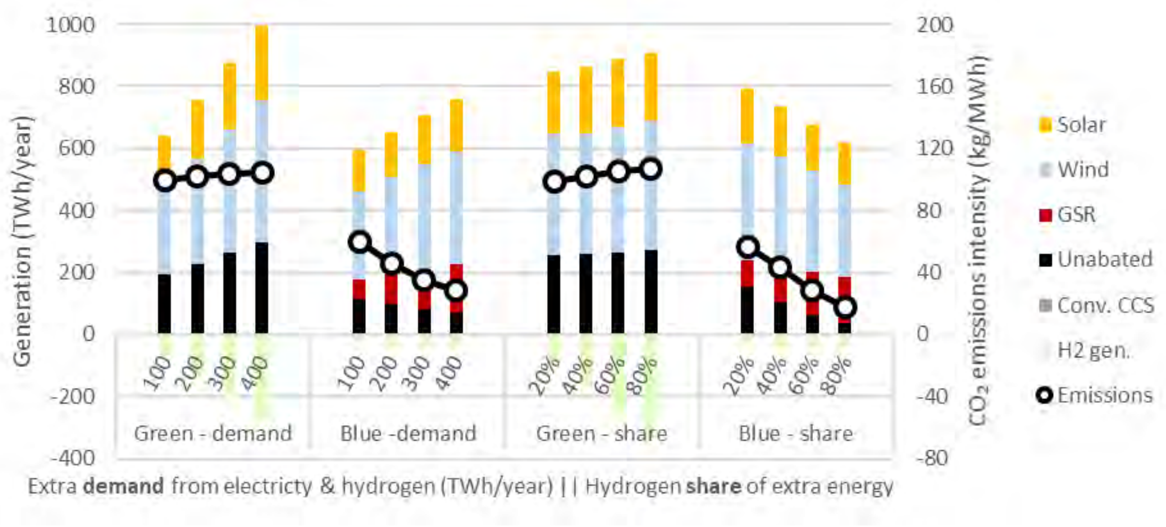

Figure 6: Breakdown of electricity generation and emissions intensity for all cases in Germany.

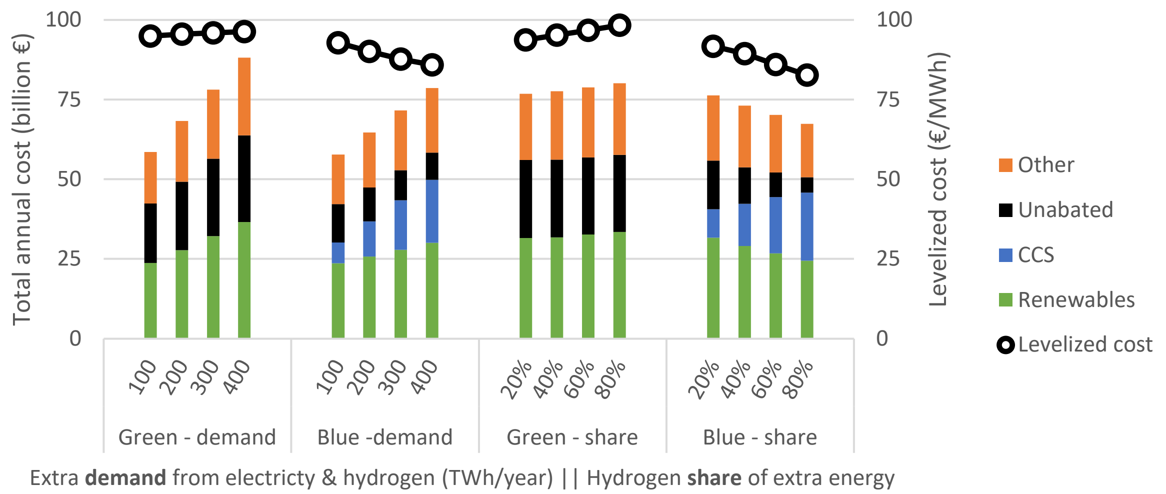

Figure 7: Breakdown of costs for all cases in Germany. Levelized costs lump together electricity, hydrogen, and heat.

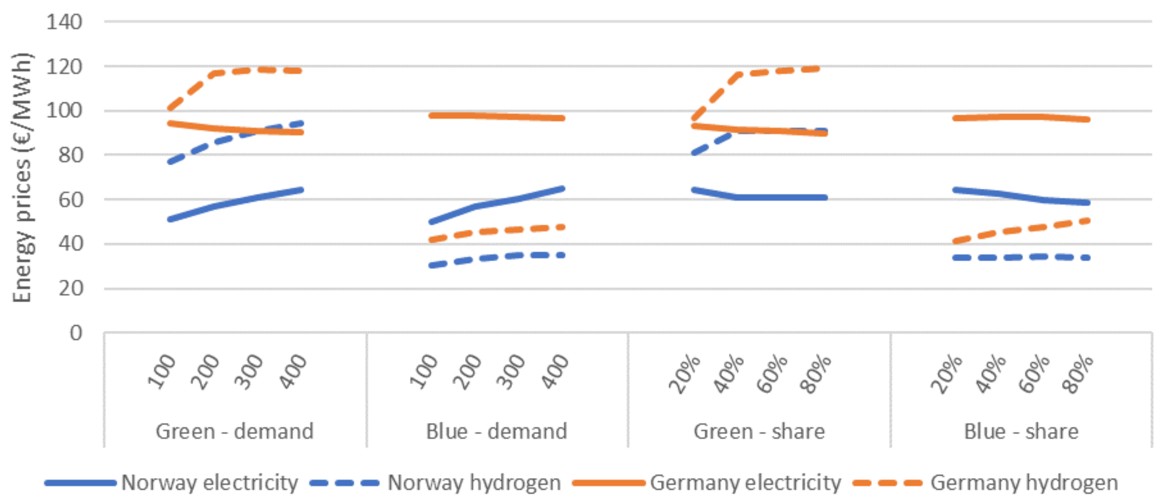

Figure 8: Volume-weighted electricity and hydrogen prices in Norway and Germany for all cases.

3.2 Germany

The electricity generation trends in Figure 6 are broadly similar to Figure 3, although the relative changes are smaller because of the much larger size of the German energy system. In addition, Germany lacks Norway's hydropower reserves and relies much more on solar power than Norway. In the Green H_2 scenario, the model relies on the maximum allowable share of unabated natural gas power generation (despite the 100 €/ton CO_2 price) to meet demand during extended periods of limited wind and sun. In the Blue H_2 scenario, the flexible power and hydrogen production from GSR [13] can increasingly be used to balance wind and solar more cost effectively as hydrogen demand increases. In general, the Green H_2 scenarios show substantially greater emissions due to the relatively high share of unabated power production required to balance variable renewables.

Cost trends in Figure 7 are also similar to Figure 4, only less pronounced because of the smaller relative changes in the overall energy system. However, levelized costs are considerably higher than in Figure 4 due to Norway's superior energy resources (hydropower, better wind resources, and cheaper natural gas). Trends in "Other" costs are also similar to that shown in Figure 5 and will therefore not be repeated here. A more detailed analysis of the German system can be found in our previous study [6].

3.3 Industrial implications (steelmaking example)

In this section, the implications for energy-intensive industry will be analyzed, using the HYBRIT steelmaking process as an example. This process uses direct-reduced iron and electric arc furnaces to produce steel, requiring 1.84 MWh of hydrogen and 0.86 MWh of electricity per ton of steel [14]. A smaller quantity of biomass is also required as a carbon source.

Using this information, the energy costs of clean steelmaking can be estimated with the modelled energy prices displayed in Figure 8. When considering electricity prices, Norway holds a large advantage over Germany due to its hydropower resources and better quality wind (which is well balanced by reservoir hydro). In the Green H_2 scenario, hydrogen prices reflect the electricity prices used to produce green hydrogen.

In the Blue H_2 scenario, electricity prices are similar to the Green scenario, but hydrogen prices are much lower. Also, the gap between Norwegian and German blue hydrogen prices is relatively small, influenced mainly by the higher natural gas cost in Germany. The large cost advantage of blue hydrogen over green hydrogen results mainly from the low natural gas price relative to the wind and solar power that must be used to produce green hydrogen. Furthermore, green hydrogen production is more intermittent, creating additional costs related to transmitting and storing large hydrogen fluxes.

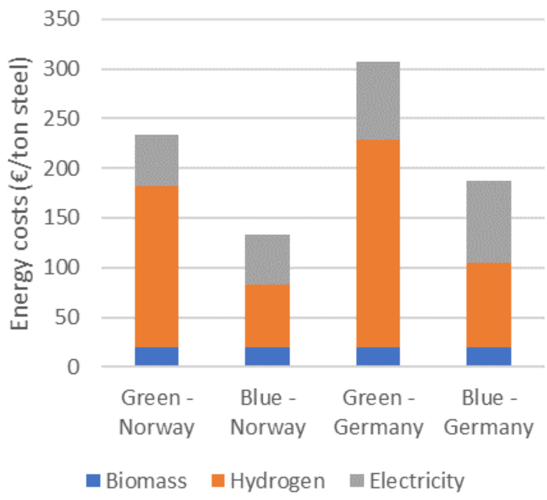

Figure 9: Energy costs for producing a ton of steel in the two different scenarios and countries.

Using the prices in Figure 8, the energy costs per ton of steel can be calculated as shown in Figure 9. Clearly, the Blue H_2 scenario produces substantially lower costs in both countries. Norway also has a sizable cost advantage over Germany in both scenarios.

Given that CCS enjoys much greater policy support in Norway than in Germany, a likely future scenario is that Blue Norway will compete with Green Germany. In this case, the energy cost difference between the two countries is 174 €/ton steel – about a third of total steel production costs.

4. Conclusions

This system-scale modelling study has illustrated the potential for oil & gas producers like Norway to export clean energy in the form of energy-intensive industrial products like steel. If CCS fails to gain political backing in energy importing regions like mainland Europe, blue hydrogen production for local consumption in heavy industry appears to be a viable way forward. If Europe does embrace CCS, the industrial cost advantage is considerably smaller, but in that case, conventional natural gas exports can continue, potentially with CO_2 being piped back for permanent storage, creating an additional revenue stream.

The robustness of these conclusions was checked by looking at a pessimistic and optimistic Blue H_2 scenario in Norway. In the pessimistic scenario, the novel and efficient GSR and biomass CHP technologies are not available, relying on conventional steam methane reforming with CCS and heat pumps for hydrogen and heat, respectively. In the optimistic scenario, half of hydrogen production is handled by membrane-assisted autothermal reforming [15], a novel technology which becomes highly attractive when hydrogen can be produced at the low pressures used for the HYBRIT process. In addition, a 20 €/ton enhanced oil recovery credit is assumed in the optimistic case.

Relative to the baseline scenario, the pessimistic case increased steel energy costs by 7.8% and the optimistic case decreased costs by 11.3%. These relatively small changes do not impact the main conclusion that energy-intensive industry fueled by local blue hydrogen appears to be a promising path forward for oil & gas producers in an uncertain decarbonizing world.

Acknowledgements

This study was funded internally by SINTEF Industry.

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