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EWI Working Paper, No 21/06

August 2021

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ISSN: 1862-3808

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Abstract

Hydrogen is gaining prominence as a critical tool for countries to meet decarbonisation targets. The main production pathways are based on natural gas or renewable electricity. LNG represents an increasingly important component of the global natural gas market. This paper examines synergies and linkages between the hydrogen and LNG values chains and quantifies the impact of increased low-carbon hydrogen production on global LNG flows. The analysis is conducted through interviews with LNG industry stakeholders, a review of secondary literature and a scenario-based assessment of the potential development of global low-carbon hydrogen production and LNG trade until 2050 using a novel, integrated natural gas and hydrogen market model. The model-based analysis shows that low-carbon hydrogen production could become a significant user of natural gas and thus stabilise global LNG demand. Furthermore, commercial and operational synergies could assist the LNG industry in developing a value chain around natural gas-based low-carbon hydrogen.

Keywords: Hydrogen, LNG, natural gas
JEL classification: Q40, Q42, Q49.

1. Introduction

The global market for liquefied natural gas (LNG) has grown significantly in recent years. Global LNG trade increased to a record 484 billion cubic metres (bcm) of natural gas in 2020, despite the COVID-19 pandemic. There is currently 616 bcm of liquefaction capacity in operation and nearly 190 bcm financially approved or under construction. The three largest exporters—Australia, Qatar and the United States—account for half the world's operational capacity. With the potential addition of Canada and Mozambique, there will be 23 exporting countries in the coming years (IGU, 2021). LNG essentially restructured the global natural gas industry and is expected to continue to play a crucial role in its development and potential growth. It is credited to have changed the role of natural gas in the world,

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moving it towards a type of globalised commodity (Colombo et al., 2016). The industry's outlook, however, could change rapidly due to the dynamic supply and demand situation globally related to the evolution of the current energy transition, particularly concerning the competitiveness of rival fuels and international decarbonisation policies. Longer-term, given that the LNG supply is due to increase at the same time as major economies adopt decarbonisation targets in line with the Paris Agreement (UNFCCC, 2015), LNG exporters must consider ways to reduce greenhouse gas emissions along the value chain, which can account for up to 20% of the total well-to-smokestack emissions resulting from the combustion of the transported gas (Roman-White et al., 2019; IGU, 2015). However, the vast majority of greenhouse gas emissions in the LNG chain are emitted at the end-use point, placing part of the responsibility on LNG importers. There are two principal ways to address these emissions: by employing carbon capture, utilisation and storage (CCUS) technology to capture and permanently store the resulting CO_2, or by switching to alternative, carbon-neutral energy carriers, such as hydrogen.

Today, hydrogen production is very localised, with 85% produced and consumed on-site, mostly at refineries (Van de Graaf et al., 2020). However, with the projected growth in demand for low-carbon hydrogen, this is likely to change as centralising production is one of the most effective ways to achieve scale. With natural gas-based low-carbon hydrogen production, natural gas will likely continue to be transformed into hydrogen locally, eliminating the need to transport hydrogen over large distances, which is more expensive than transporting natural gas (Abánades, 2018).

In a series of reports published by the Oxford Institute for Energy Studies, Stern (2017, 2019a,b, 2020) explores the future role of natural gas, the natural gas value chain, and the LNG industry in the context of decarbonisation. The author highlights that the natural gas industry must move forward from the coal-to-gas switching narrative of the recent decade and respond to rapidly to market requirements regarding decarbonisation, mainly in Europe. Therefore, LNG exporters must address the issue of methane emissions and increase transparency, but in the medium to long term, even contemplate full decarbonisation by using LNG to produce natural gas-based low-carbon hydrogen.

Accordingly, recent reports examining decarbonisation pathways for the global energy system (e.g. IRENA (2019), BP (2020), Shell (2020), IEA (2020a,b, 2021b)) all predict growing importance of low-carbon hydrogen as an alternative energy carrier, with a substantial market for the commodity developing by 2050. At the same time, all projections expect global natural gas consumption to peak and then fall as decarbonisation deepens (see Table 1).

Many studies have identified and compared technical pathways for natural gas producers to produce low-carbon hydrogen (Bollen et al., 2010; Voldsund et al., 2016; Salkuyeh et al., 2017; Parkinson et al., 2018; CE Delft, 2018; Brändle et al., 2021). As the fastest-growing segment within natural gas, LNG could play a key role in delivering natural gas to markets that can then be used to produce hydrogen.

Table 1: Projected global demand for hydrogen and natural gas in major decarbonisation scenarios

		2030		2040		2050	
Source	**Scenario**	**Hydrogen** *(Mt)*	**Gas** *(Mtoe)*	**Hydrogen** *(Mt)*	**Gas** *(Mtoe)*	**Hydrogen** *(Mt)*	**Gas** *(Mtoe)*
IEA (2020a)	ETP SDS	35	-	102	3056	258	2384[1]
IEA (2020b)	WEO SDS	18	3312	75	2943	164	-
IEA (2021b)	Net Zero	149	3081	353	1791	520	1433
BP (2020)	Rapid	5	3941	64	3774	199	3392
	Net Zero	6	3368	162	2508	483	2173
Shell (2020)	Sky	4	3750	18	3607	73	2747
IRENA (2019)	REMap	-	3057	-	2484	242	1767

[1]The 2050 value for the ETP SDS scenario was derived by linearly interpolating between the 2040 and a 2070 estimate (2048 Mtoe) given by the source. Mt = Million tonnes. Mtoe = Million tonnes of oil equivalent.

The choice of pathway depends on the actors involved, whose decisions will be influenced by market conditions, price signals, regulatory environments, technology risk, existing infrastructure, and potential future infrastructure (Hanley et al., 2015).

In the emerging market for low-carbon hydrogen, natural gas-based technologies such as natural gas reforming (NGR)[1]+CCUS or methane pyrolysis are likely to compete against electrolysis using electricity derived from renewable energy sources (RES) as the primary means of hydrogen production (Brändle et al., 2021).

The degree to which each technology contributes to the supply mix depends on policy choices, especially in the short to medium term. As the market for low-carbon hydrogen matures, however, technologies with significant cost advantages over others are likely to come to dominate the supply mix.

As shown by Brändle et al. (2021), natural gas-based technologies are likely the most economical choice to produce low-carbon hydrogen in the short to medium term. However, in the long term, RES-based hydrogen could become competitive in countries with good renewable resources if RES and electrolyser investment costs decline substantially and natural gas prices increase (IEA, 2019a; Brändle et al., 2021; Lambert and Schulte, 2021). Amongst the natural gas-based technologies, NGR+CCUS could be supplemented by methane pyrolysis if it becomes mature enough to be deployed at scale for hydrogen production. The pyrolysis process itself generates no CO_2 emissions, leaving only a solid carbon by-product which is easier to manage and store than gaseous CO_2. The technology has the potential to produce low-carbon hydrogen at a very low cost when feed gas costs are low. However, when and at what scale and cost pyrolysis will become available is uncertain.

Depending on how the global low-carbon hydrogen supply technology mix and the associated market structure develop, there are significant implications for natural gas producers and the LNG market. Suppose

[1]In this paper, *natural gas reforming* refers to the production of hydrogen from natural gas using steam methane reforming (SMR), autothermal reforming (ATR) or partial oxidation (POX).

low-carbon hydrogen production is primarily natural gas-based. In that case, it could potentially act as a brake on the long-term decline of global natural gas consumption that is otherwise projected to occur in a deep-decarbonisation scenario.

Furthermore, the LNG industry may leverage technical or commercial synergies when it comes to producing, shipping, and marketing low-carbon hydrogen. Transferable know-how could play a role in developing technology and methods based on delivering and handling large amounts of gas over long distances. In addition, the development of an international market for low-carbon hydrogen may mirror that of the LNG market, where large producers and customers underpinned the early stages of market development, supported by strategic government support that eventually led to a dynamic near-commodity type market. However, whether exports of RES-based hydrogen are a viable alternative for some of the current LNG producers is an open question that hinges on the technology and economics of exporting hydrogen, particularly by ship. It depends on the cost of shipping hydrogen, the proximity to export markets and other factors, such as the integration into potential regional hydrogen pipeline networks. The issues described above can be distilled into two main research questions, which this paper will address:

- What impact could increasing demand for low-carbon hydrogen have on the global LNG market?
- Do potential synergies exist between the LNG and hydrogen industry value chains—commercial and technical—that LNG producers could leverage?

We perform a model-based scenario analysis to quantify the impact of different global low-carbon hydrogen development pathways on LNG exporters using a novel, integrated natural gas and hydrogen market model. The chosen pathways are based on recent projections by the International Energy Agency (IEA) and consistent with a deep decarbonisation of the global energy system by 2050.

The scenario analysis is supplemented by interviews with LNG industry stakeholders and a review of secondary literature to derive further insights. The interviewees represent a range of actors, including market experts, traders, consultants, traders and producers (see Appendix A).

2. Model-Based Analysis

The model-based scenario analysis is conducted using a model of the global markets for natural gas and low-carbon hydrogen. It is based on COLUMBUS, a partial equilibrium model of the global natural gas market, developed by Hecking and Panke (2012), and subsequently applied in analyses by, among others, Growitsch et al. (2014) and Schulte and Weiser (2019).

The extended model covers several stages of natural gas and hydrogen value chains (production, transport, storage and consumption) across 90 countries globally. It is formulated as a mixed complementarity problem (MCP).

For the paper at hand, the model is run in an annual resolution. Spatially, it is defined by a set of nodes that are connected through arcs. Nodes are divided into natural gas and hydrogen production, liquefaction, regasification and consumption nodes, and the arcs connecting them represent pipelines and LNG/liquid hydrogen (LH_2)[2] shipping routes.

The model is populated by different profit-maximising agents: exporters, producers, transmission system operators (TSOs), liquefiers, regasifiers and shippers. Subject to various constraints, they maximise their profits by making optimal decisions with respect to the production, sale and transport of natural gas or hydrogen and through optimal investments into production and transport infrastructure.

The partial equilibrium model is formed by combining the first-order optimality conditions of the respective optimisation problems of the individual agents situated along the natural gas and hydrogen value chains with the market clearing conditions of the respective markets. A detailed mathematical description of the model is provided in Appendix C.

2.1. Scenarios

To quantify the impact of technology choices on the ramp-up of a global market for low-carbon hydrogen, the natural gas market more broadly, and LNG in particular, we develop four transition scenarios. They are based loosely on the IEA's Sustainable Development Scenario (SDS) (IEA, 2019b, 2020a,b), supplemented by own assumptions on the distribution of the aggregated natural gas and hydrogen demand estimates provided by the IEA to the individual countries covered by the model. The SDS's natural gas and hydrogen demand trajectories are consistent with a rapid decarbonisation of the global economy.

The scenarios represent different possible trajectories for the evolution of the low-carbon hydrogen production technology mix. We consider RES-, natural gas- and coal-based low-carbon hydrogen production pathways. The modelled RES-based pathways rely on the electrolysis of water using electricity from onshore wind, offshore wind, or solar PV. The natural gas-based technologies are NGR+CCUS and methane pyrolysis, as described in Brändle et al. (2021). RES- and natural gas-based technologies are assumed to be available globally, while coal gasification (CG) is modelled as an additional option specifically for China. It is by far the world's largest producer of hydrogen from coal today, being home to more than 80% of the world's coal gasification capacity (IEA, 2019a). We assume that the country is likely to keep using the technology—with the addition of CCUS—to meet some of its future low-carbon hydrogen requirements, while coal production is projected to decline substantially or be phased-out entirely in most other parts of the world (IEA, 2020a,b).

[2] While converting hydrogen to ammonia for shipping represents the lowest-cost option of transporting hydrogen by sea today—since existing infrastructure (liquefied petroleum gas tankers and port facilities) can be leveraged—LH_2 has the potential to become the lowest-cost technology in the long run, if pure hydrogen is the desired end product and LH_2 shipping is deployed at scale (Brändle et al., 2021).

The first three scenarios (collectively labelled open transition [OPT]) represent a world in which hydrogen production technologies compete solely based on their levelised cost of production.

To assess the impact of different future RES and electrolyser costs, we compare a scenario in which RES and electrolyser cost reductions follow a baseline trend with a scenario in which costs fall further (low-cost). Pyrolysis is currently not a mature technology deployed at scale for the purposes of hydrogen production. To account for the uncertainty around its eventual application and to assess its potential impact on hydrogen production and natural gas consumption, we model a separate scenario in which pyrolysis becomes available after 2030 in a setting with low RES and electrolyser costs (OPT [low cost/pyrolysis]). In the other two scenarios (OPT [baseline] and OPT [low-cost]), pyrolysis is assumed not to be available, making NGR+CCUS the default option when it comes to natural gas-based low-carbon hydrogen production.

Finally, as a special case, we simulate the so-called green transition (GRT) scenario, where RES-based production technologies dominate the global low-carbon hydrogen supply mix as a matter of policy choice.

Broadly speaking, the four scenarios are differentiated along two dimensions: the RES/electrolyser cost case (baseline vs low cost) and the availability of fossil fuel-based low-carbon hydrogen production technologies (Table 2).

Table 2: Overview of scenarios

	OPT (baseline)	**OPT (low cost)**	**OPT (low cost/pyrolysis)**	**GRT**
RES cost case	baseline	low cost	low cost	baseline
Pyrolysis	unavailable	unavailable	available	unavailable
NGR+CCUS	available	available	available	unavailable
CG+CCUS	available	available	available	unavailable

The four scenarios are not to be taken as predictions. Instead, they are designed to provide benchmarks regarding the impact of low-carbon hydrogen production on the natural gas sector. In reality, developments may be less clear-cut than predicted by the model, as technological choices are likely to be shaped as much by policy choices in different regions as they are by economics.

The scenarios are assessed with respect to overall production and consumption trends, the size of the LNG and hydrogen markets, and the impact on LNG and hydrogen trade flows. We analyse and present results for the years 2030, 2040 and 2050.

2.2. Data and Assumptions

This section outlines key assumptions made for the model-based scenario analysis of the markets for natural gas and low-carbon hydrogen.

Natural gas and hydrogen demand

We assume identical natural gas and hydrogen demand trajectories for all four scenarios. The consumption pathways are based on the IEA SDS and therefore consistent with a global transition to net-zero emissions by 2070 (IEA, 2020a,b).

Global natural gas demand (excluding consumption to produce low-carbon hydrogen, which is determined endogenously by the model) continues to grow to 3945 bcm in 2030, with demand growth in the Asia Pacific offsetting a decline in consumption in other regions, in particular Europe and North America. After 2040, the pressure to decarbonise leads to demand falling in Asia as well. Global consumption then declines to 3285 bcm in 2040 and 2534 bcm in 2050.

The IEA (2020a) projects global demand for low-carbon hydrogen to increase sharply after 2030, rising from 35 Mt to 258 Mt until 2050. In 2050, 37% is consumed in the transport sector[3] 34% in industry[4] and 10% in the buildings sector. The remaining 19% are consumed in other sectors, most notably the power sector, where hydrogen provides an important source of backup power for intermittent RES, displacing natural gas (IEA, 2020a). Since the agency does not provide a country-level breakdown of its consumption estimates, we allocate it based on projected GDP (OECD, 2018) (for industrial and transport sector hydrogen consumption) and natural gas consumption (for buildings and other sectors). We further assume that in 2050, most of the hydrogen (80%) is still consumed in the high-income economies[5] and China, the likely front runners when it comes to decarbonisation. According to this distribution, more than 40% of the hydrogen is consumed in the Asia Pacific region in 2050, followed by North America (25%) and Europe (18%) (see Figure 1).

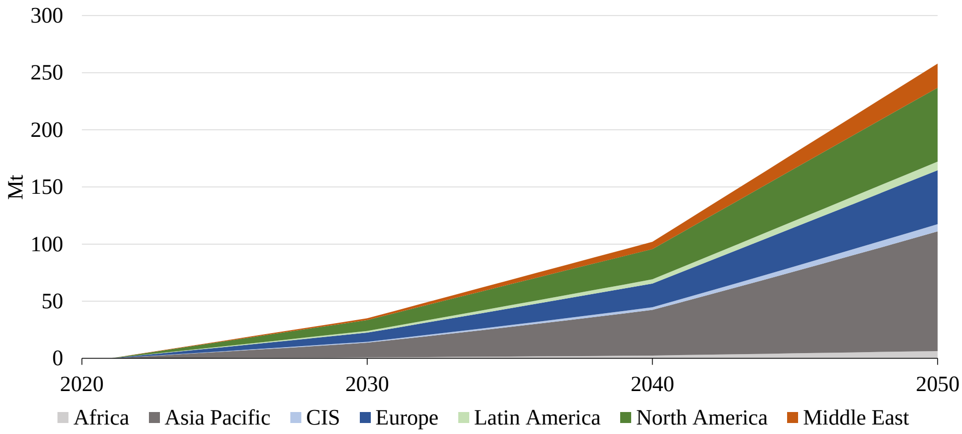

Figure 1: Assumed development of global demand for low-carbon hydrogen

[3]Including hydrogen used for the production of synthetic fuels.

[4]Including hydrogen used in refining and for the production of low-carbon ammonia.

[5]As defined by the World Bank.

It should be noted that we assume both the natural gas and the emerging market for low-carbon hydrogen to be perfectly competitive. Historically, large natural gas producers like Russia were at times in a position to exert market power in certain regions, such as Europe. However, in recent years, the market has become much more competitive, not least because of the increasing role LNG plays in providing liquidity and linking the hitherto segmented markets of North America, Europe, and East Asia (Growitsch et al., 2014; Schulte and Weiser, 2019).

Natural gas and hydrogen supply costs and potentials

Country-level natural gas supply cost curves are built from proprietary field-level cost and capacity projections provided by Rystad Energy (2020).

Data on current and future investment costs, operating costs, and the conversion efficiencies of RES- and natural gas-based hydrogen production technologies are taken from a comprehensive global assessment of low-carbon hydrogen production costs published by Brändle et al. (2021). Investment costs, operating costs and conversion efficiencies for CG+CCUS in China are obtained from IEA (2019a, p. 51).

For NGR+CCUS and CG+CCUS, the cost of transporting and storing CO_2 underground is an important cost component. We estimate country-level CO_2 storage costs (see Table B.4) using data on CO_2 transport costs and reservoir-specific storage costs provided by Roussanaly et al. (2014) and Rubin et al. (2015).[6]. We assume both NGR+CCUS and CG+CCUS have a CO_2 capture efficiency of 90%. The residual emissions are subject to the local CO_2 price[7].

Brändle et al. (2021) provide detailed, disaggregated information on RES potentials and costs for the countries represented in the model. There are two cost cases for RES-based hydrogen: in the baseline case, RES and electrolyser costs decline so that in locations with above average onshore wind or PV conditions, the levelized cost of hydrogen drops to around \$2/kg by 2050. In the low-cost case, higher RES investment cost reductions are achieved, in particular for solar PV, and levelised hydrogen production costs dip to \$1/kg in locations with good solar potentials.

To take account of variations in investment risk and financial conditions between countries, all investments are discounted using country-specific weighted average cost of capital estimates (see Table B.4).

[6] We do not consider potential limitations to the underground storage of CO_2 in certain areas. In some cases, nearby reservoirs may not be readily available, and the CO_2 would have to be transported over greater distances to suitable disposal sites, increasing the associated cost. However, as shown by Brändle et al. (2021), the impact of an escalation in the cost of CO_2 transport and storage on the levelised cost of hydrogen produced by NGR+CCUS is relatively low.

[7] It should be noted that in reality, CO_2 prices would likely vary from scenario to scenario, in particular if hydrogen or hydrogen-based technologies—for which we model different cost trajectories—are the marginal abatement option. However, we are unable to model this link in the partial equilibrium model used for this study. We therefore assume an exogenous global CO_2 price, based on IEA (2019a) and IEA (2020b), which increases from \$89/tCO_2 in 2030 to \$165/tCO_2 in 2050 in advanced economies and \$70/tCO_2 in 2030 to \$145/tCO_2 in 2050 in less advanced economies in all scenarios.

It should be noted that we did not explicitly model a pessimistic cost development trajectory for RES and electrolysers. However, such a possibility should not be discounted. Some analyses predict a decline in the energy return on energy invested (EROI) of the global energy system when comparably energy dense fossil fuels are phased out in favour of less energy dense renewables. This would result in an increase in the materials intensity of the global economy (Capellán-Pérez et al., 2019). A consequence of a re-materialisation of the global economy would be a smaller decline in RES investment costs than currently anticipated, or possibly even an increase in the long run. However, given the cost advantage natural gas based hydrogen currently enjoys, simulating a pessimistic cost trajectory for RES would yield little additional insight compared to the baseline case, since it would simply show a preservation of the near-term cost advantage which natural-gas based low-carbon hydrogen production pathways enjoy in all of the major economies (Brändle et al., 2021).[8]

Natural gas and hydrogen transport

Data on existing cross-border natural gas pipeline capacities is obtained from an in-house database maintained by the Institute of Energy Economics at the University of Cologne. LNG liquefaction/regasification capacities (existing and sanctioned) are sourced from IGU (2021). Current long-term contracts (LTCs) for pipeline gas and LNG are modelled as well, with contract volumes and durations obtained from Rystad Energy (2020). Existing LTCs are assumed not to be renewed after expiry. Investment costs for natural gas pipelines and LNG infrastructure come from various sources, including company reports and publications by the Oxford Institute for Energy Studies (Songhurst, 2018; Steuer, 2020).

For the seaborne transport of hydrogen, we model an infrastructure consisting of hydrogen liquefaction terminals, liquid hydrogen (LH_2) tankers and regasification terminals, with projected investment and operating costs of all three elements sourced from Brändle et al. (2021).

For land-based transport, pipelines are the lowest cost technology to transport significant volumes of hydrogen over large distances. In line with Brändle et al. (2021), we assume the specific cost for the transmission of hydrogen through new, large-scale, dedicated hydrogen pipelines to fall to \$240 per tonne of H_2 per 1000 km by 2030.

3. Results and Discussion

3.1. Model Results

The model simulations show (Figure 2) that in the open transition (OPT) scenarios—where the different low-carbon hydrogen production technologies compete based on cost—the initial development of

[8] As shown in Section 3.1 below, this intuition is confirmed by model runs using baseline RES cost assumptions. They show that in the OPT (baseline) scenario, natural gas-based low-carbon hydrogen production remains the lowest-cost solution in almost all modelled countries until 2050. This would evidently also be the case with more pessimistic assumptions on the development of RES and electrolyser costs.

the hydrogen market in 2030 is supported almost exclusively by NGR+CCUS. This applies to both the baseline (*OPT (baseline)*) and low RES/electrolyser (*OPT (low cost)*) cost cases. However, with a more aggressive decline in the cost of RES and electrolysis, RES-based hydrogen production becomes competitive with NGR+CCUS, particularly in regions with good PV potentials. In the *OPT (low cost)* scenario, roughly a third of global low-carbon hydrogen production in 2050 is RES-based. The calculations also show that coal gasification, combined with CCUS, remains the mainstay of hydrogen production in China.

In the *OPT (low cost/pyrolysis)* scenario, natural gas pyrolysis is available as an alternative for the natural gas-based production of hydrogen. Since it does not require CCUS equipment, the associated investment costs are projected to be lower than for NGR+CCUS. Consequently, it becomes the lowest-cost natural gas-based hydrogen production technology once available, despite its lower efficiency and, therefore, higher natural gas consumption. The *OPT (low cost/pyrolysis)* scenario also shows that the cost differential between RES- and natural gas-based technologies is relatively narrow even in regions with good RES potentials: the cost reduction associated with the use of pyrolysis in this scenario is enough to make it the dominant technology in almost all modelled countries once it becomes available.

Generally, the strong performance of natural gas-based hydrogen is the result of persistently low natural gas prices in all major consumption regions (see Figure 4 below), triggered by a levelling off and decline of global natural gas consumption (see Figure 3 below).

In the green transition (*GRT*) scenario, an assumed global preference for RES-based hydrogen ensures that low-carbon hydrogen is produced exclusively from RES in all countries. Furthermore, the scenario shows an increase in the relative importance of PV-based hydrogen in the supply mix as production scales up since the cost of PV-based electricity is projected to decline more than from onshore or offshore wind turbines.

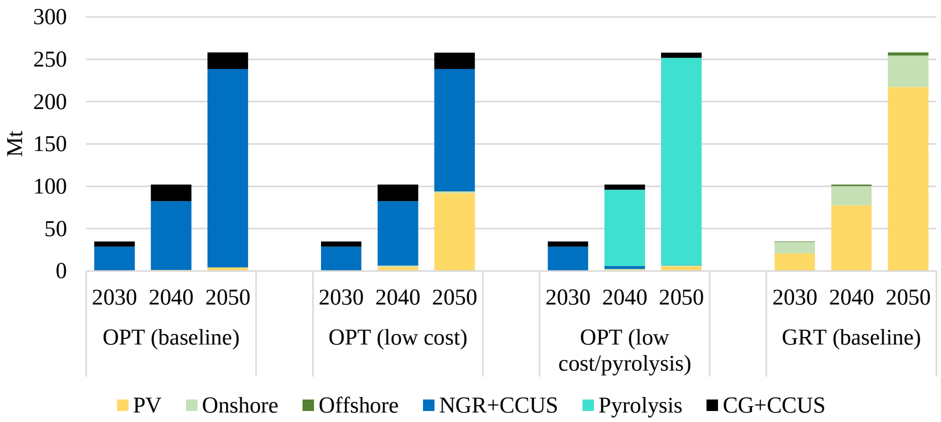

Figure 2: Evolution of global low-carbon hydrogen production

Comparing the four scenarios illustrates significant differences concerning the spatial structure of the emerging hydrogen market. In the OPT scenarios, hydrogen production is overwhelmingly based on natural gas and generally occurs close to where the hydrogen is consumed. In the case of NGR+CCUS, the resulting CO_2 is stored locally. Furthermore, due to the lower associated cost, international trade is overwhelmingly in the form of natural gas and LNG, rather than gaseous or liquid hydrogen.

However, as the share of RES-based hydrogen increases, so does the importance of cross-border trade, linking countries/regions with low production costs to countries with high demand but less favourable conditions to produce hydrogen from RES. In the GRT scenario, the share of internationally traded hydrogen is highest in 2030 with 68% of the hydrogen consumed globally traded across international borders. This share declines to 37% of global demand by 2050 as the lowest-cost RES potentials are used up, and production technology costs fall, making production in countries with less favourable RES conditions competitive with imports.

The simulations reveal that pure hydrogen is generally traded in regional clusters via pipeline, forming several regional rather than a global market. Due to the high cost of shipping hydrogen compared to pipelines, hydrogen is generally not traded by sea. The notable exception is Japan, which in the GRT scenario imports LH_2 from the Middle East.

As shown in Figure 3, the substantial increase in natural gas-based hydrogen production in the *OPT (baseline)* and *OPT (low cost/pyrolysis)* scenarios supports global natural gas demand, slowing down or reversing the decline in natural gas consumption between 2030 and 2050. In some regions with a strong decline in natural gas demand before 2040, such as Europe, the substantial rise in local natural gas-based hydrogen production leads to a rebound in demand between 2040 and 2050. In the OPT (low cost) scenario, the higher reliance on RES-based hydrogen production leads to a general decline in global natural gas consumption, which is even more pronounced in the *GRT* scenario, where all hydrogen is produced from RES.

In contrast to the gas market as a whole, the LNG market continues to grow until 2050 in the *OPT (baseline)* and *OPT (low cost/pyrolysis)* scenarios, since a significant share of the additional hydrogen production takes place in the large economies of the Asia Pacific region, which are significantly more reliant on LNG imports than, for example, countries in Europe or North America. In the *OPT (baseline)* scenario, the 2050 LNG market in 2050 is approximately 30% bigger than in 2020[9]. In the *OPT (low cost/pyrolysis)* it even grows by 60% over the same time period.

In the *OPT (low cost)* scenario, by contrast, the increasing share of RES-based hydrogen production in 2040 and 2050 and the smaller associated demand for natural gas affect the LNG market. Since most of the early decline in natural gas consumption is in North America and Europe, while consumption in

[9] According to IGU (2021), 484 bcm of LNG were shipped in 2020.

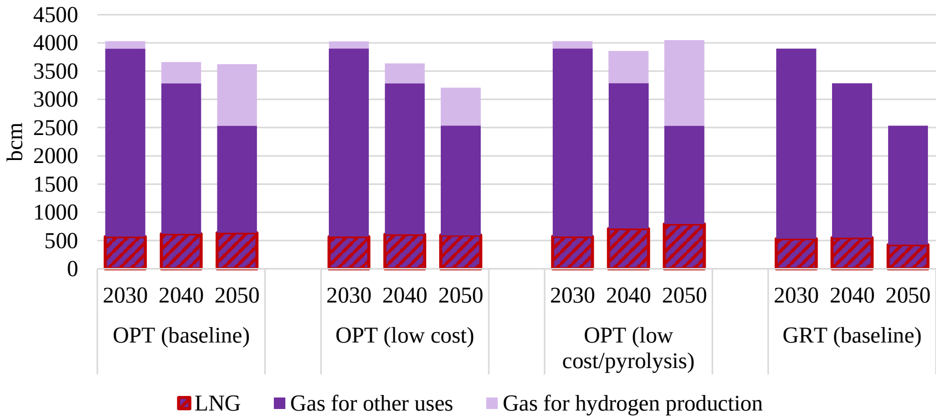

Figure 3: Development of global natural gas consumption and the share of LNG

the Asia Pacific region increases until 2040, the LNG market will continue to grow until 2040, albeit more slowly, with demand peaking in 2040 and then declining slightly until 2050. The post-2040 decline is even more pronounced in the *GRT* scenario, where low-carbon hydrogen production is exclusively RES-based. Consequently, the global LNG market is 12% smaller in 2050 than it was in 2020.

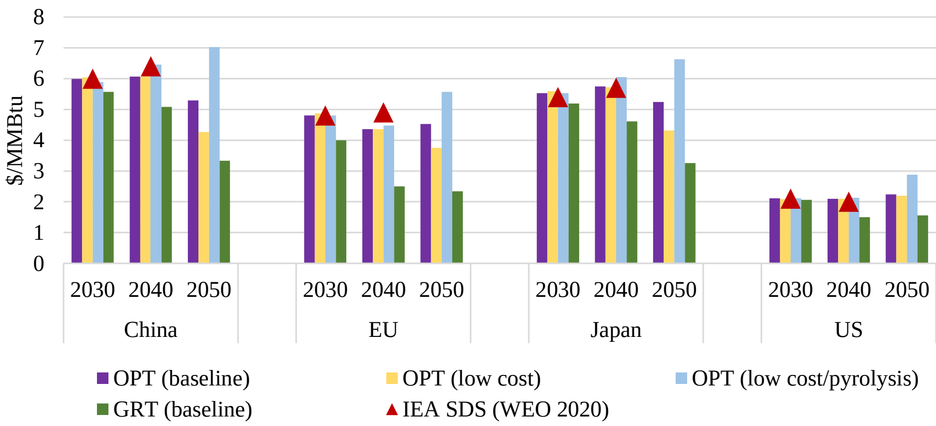

Figure 4: Development of natural gas prices in selected regions

The simulations reveal that the growth of the LNG market in the *OPT (baseline)* and *OPT (low cost/pyrolysis)* scenarios is driven primarily by rising demand in the Asia Pacific and, to a lesser degree, Africa. Compared to today, market shares in the large East Asian LNG market shift: exports from the Commonwealth of Independent States (CIS) and North America to Asia increase significantly. Exports from the Middle East to the Asia Pacific increase as well, with India and later Southeast Asia becoming the two largest off-takers for cargoes from the region. European LNG imports decline substantially from today's levels. For Europe, shipments from the United States increase in importance, compared to a reduction in imports from the Middle East. Low-cost suppliers of LNG are less affected by constrained demand. High-cost producers, on the other hand, located mainly in the Asia Pacific and North America are—by virtue of their higher relative cost base—much more sensitive to differences in LNG demand resulting from different hydrogen pathways. They act as "swing suppliers" and primarily make up for the differences in volumes between the four scenarios.

A detailed overview of the LNG trade flows calculated for each scenario is presented in Table D.5 in Appendix D.

3.2. Discussion

3.2.1. Impact on the LNG Market

The scenario analysis presented in the previous section shows that hydrogen production could become a significant user of natural gas by 2040, provided that the ramp-up of the growing market for low-carbon hydrogen is supported mainly by natural gas-based technologies. As a result, it could stabilise global natural gas demand, compensating for the decline in natural gas consumption by other sectors that accompanies the global economy's progressive decarbonisation. LNG producers would be the primary beneficiaries of such a development since the lion's share of low-carbon hydrogen is likely to be consumed in the advanced economies of the Asia Pacific region—due to their size and overall energy demand. On average, these economies rely more on LNG imports than on domestic natural gas production or imports via pipeline.

The strong performance of natural gas-based hydrogen production in the model-based analysis confirms industry expectations: in the interviews conducted for this study, it was noted that the cost and complexity of developing RES-based hydrogen would lead to more natural gas-based hydrogen introduced to energy systems in the short to medium term than projected by many experts and forecasters, even in regions such as Europe that are primarily supporting the development of electrolysis using RES electricity. The overwhelming view of participants was that the need to make progress towards net-zero would push countries to embrace an "all of the above" approach to hydrogen.

Several interviewees remarked that an early ramp-up using natural gas-based hydrogen in the short to medium term, followed by an increase in RES-based hydrogen production in the long run, is likely to reflect how the energy system will develop. It was noted that the development of a technology mix, taking advantage of supply economics, regulatory support, and technological improvements, is what is likely to unfold. From the modelled scenarios, the *OPT (low cost)* scenario, where natural gas-based hydrogen becomes the dominant pathway in some regions and RES-based hydrogen in others, is the closest approximation of such an outcome. The calculations reveal that in this scenario—which assumes a substantial decline in RES and electrolyser investment costs over the coming decades—the cost margin between natural-gas based and RES-based hydrogen is relatively narrow in several regions in 2050. As a result, small differences in the gas price can significantly impact the relative competitiveness of both production pathways, leading to large differences in hydrogen-related natural gas consumption.

All four modelled scenarios postulate an aggressive decarbonisation of the global economy. In this context, the outlook for the LNG market itself could potentially still be robust until 2050, provided low-carbon hydrogen production is overwhelmingly natural gas-based. However, in scenarios where RES-based hydrogen production predominates, slow growth until 2040 followed by a shallow decline until 2050. This outcome aligns with the perception of the interviewed LNG industry stakeholders, who identified RES-based hydrogen as a downside risk to the LNG industry in the long term. Several interviewees noted that resource holders could take major strategic decisions to leverage their asset base subject to the availability of low-carbon resources, but that a long term future based primarily on RES-based hydrogen would be very disruptive to LNG. An energy expert concluded that it would be very tough to see a viable path for LNG under a RES-based hydrogen pathway, stating that "definitely blue all the way through" needs to be the approach for the industry.

3.2.2. Strategic Implications

Within the broader context of decarbonisation in general, interviewees representing different parts of the LNG industry identified several key opportunities in the coming decades. First, there is still significant scope to support coal-to-gas switching in many parts of the world, mainly Asia, and at the same time support the continued deployment of renewables by providing large-scale backup capacity, mainly in developing economies. LNG represents an easy "bolt-on strategy that can be implemented right away" supported by a mature market and developed logistical value chain, especially when compared to more unproven technologies that require significant support to develop. Second, several interviewees highlighted that industrial clusters could represent an opportunity to leverage LNG import facilities for hydrogen development. A cluster strategy focusing on on-site NGR with CCUS or pyrolysis and access to RES, which can eventually be used to produce hydrogen, would introduce the possibility of a phased decarbonisation of large energy consumers in Europe initially and subsequently in other parts of the world as well. In addition, transferable skills related to the operation of cryogenic liquids and the management of complex long-distance supply chains were identified as potential areas of synergy between hydrogen and LNG.

Cluster strategies have also received treatment in the literature. According to IEA (2019a) industrial clusters where LNG import terminals are located could provide an opportunity for LNG to be imported and low-carbon hydrogen to be produced at the same location. Coastal industrial clusters with large dependable industrial customers represent one of the main near-term opportunities where existing gas infrastructure can support the scale-up of low-carbon hydrogen production and consumption (IEA, 2019a; BNEF, 2020; IEA, 2021a). Furthermore, blending natural gas with low-carbon hydrogen in pipelines is often proposed to support the introduction of hydrogen as an energy carrier while reducing the emissions attributed to natural gas (Hanley et al., 2015; Speirs et al., 2018). However, the direct use of hydrogen is much more economical than blending in the short to medium term (Schlund and Schönfisch, 2021).

In terms of threats, several interviewees highlighted an increasing risk that specific energy systems might skip the traditional evolution from coal to natural gas to renewables for power generation, mainly due to rapid cost reductions of renewables, which could expedite the development of RES-based hydrogen. It was broadly agreed that although China and India will be the key markets for LNG's potential growth in the coming decades—something that is also shown by the model-based scenario analysis conducted in the paper at hand—other important markets in Asia, South American and Africa are important, yet at the same time have some characteristics that could limit LNG's bridging role, such as domestic coal and rich renewables resources. Overall, the greenhouse gas emissions of LNG are perceived as a risk for the industry, partly due to growing anti-fossil fuel sentiment in key export markets, but also partly because of the resulting dependence on CCUS as a technology that has yet to be deployed at scale, with doubts expressed on the long-term impact of carbon-neutral cargoes.

While natural gas-based low-carbon hydrogen production may play a major role in supporting LNG exports, the model-based scenario analysis also shows that directly exporting pure hydrogen does not appear to be a viable option for most LNG producers. If natural gas-based hydrogen production technologies dominate, transporting gas instead of hydrogen is the more economical option, with hydrogen production generally taking place close to where it is consumed. If hydrogen production is mainly RES-based, more hydrogen is traded internationally, but mainly via pipeline, with the market divided into regional clusters. Due to the higher relative cost vis-à-vis pipelines, ship-based imports of hydrogen are only relevant for Japan, which lacks suitable amounts of low-cost renewables to produce all of the hydrogen it needs domestically and is—for geographic reasons—dependent on additional seaborne imports.

While not explicitly covered by the model-based analysis presented in the paper at hand, producing and exporting low-carbon ammonia and synfuels may present an additional opportunity for exporters since they are less costly to ship than pure hydrogen. In the IEA SDS, for example, ammonia and synfuels production accounts for 17% of global hydrogen-related final energy demand in 2040 and roughly 30% in 2070 (IEA, 2020a). Currently, ammonia production generally takes place close to where it is consumed and where natural gas is available, and refined fuels are similarly produced locally from imported crude oil. However, if hydrogen production is predominantly RES-based, it may be more economical to locate ammonia and synfuel production facilities in regions with low-cost renewable energy potentials and export the commodities. Existing infrastructure could potentially be leveraged to support such exports. The LNG chain, for example, could handle synthetic methane as well. Nevertheless, if pure hydrogen is the required end-product, it is likely to be more economical to produce, transport and consume the hydrogen directly, thereby avoiding the costs associated with the conversion into a hydrogen-based energy carrier, followed by a reconversion to hydrogen (Brändle et al., 2021).

Several studies have explored potential technical and operational synergies between LH_2 and LNG, focusing on production methods, shipping, and storage (Abe et al., 1998; Bang et al., 2011; Hanley et al., 2015; Lloyd's Register and UMAS, 2019). However, hydrogen requires significantly colder temperatures to become a cryogenic liquid (-253 degrees Celsius compared to -161 degrees Celsius for LNG). Liquefying hydrogen would between 25%-35% of the hydrogen to provide the necessary energy, compared to 10% for natural gas (IEA, 2019a). In terms of shipping, LNG bunkering infrastructure is unlikely to be suited for LH_2. Retrofitting could be as expensive as building new infrastructure (different cooling equipment and insulation are required), even though both LH_2 and LNG require cryogenic treatment.

However, there are commercial synergies to explore. Several major potential future importers of hydrogen are already significant LNG importers with established links to LNG exporters, such as Japan and Korea, which possess transferable commercial and value chain management knowledge (ARENA, 2018). The hydrogen industry could develop similarly to the LNG industry, through the initial establishment of a hydrogen market based on long-term bilateral contracts, supported by government-to-government agreements, and take or pay commitments to support and underpin investment into hydrogen production, storage and transport assets (Bruce et al., 2018; Van de Graaf et al., 2020). Initial supply agreements could also benefit from negotiating favourable trade tariffs, supported by joint ventures that leverage current commercial relationships and share risk through a vertically integrated approach (Bruce et al., 2018).

Australia is an example of an important LNG exporter that looks to leverage its LNG position and expertise to support its hydrogen export plans. It has developed a national hydrogen roadmap and strategy, focusing initially on electrolysis and then at a later stage the large scale production of hydrogen utilising brown coal (Bruce et al., 2018; Van de Graaf et al., 2020). The roadmap developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO), Australia's national science research agency states that "lessons learnt from the LNG industry" include mimicking the origins of LNG market development leaning on government-to-government agreements to support long term off-take contracts to secure stable and sufficient financing (Bruce et al., 2018, p. 53).

Generally, the hydrogen industry was characterised as still in an early stage by interviewees. While low-carbon hydrogen was accepted as technically viable and a component of the future energy system, the current lack of infrastructure and its high overall cost mean that hydrogen will require substantial government support, similar in scale to that of renewables in Europe over the past several decades, which could translate to slower adaptation rates than many forecasts predict. Technical challenges linked to transport and the current overall fragmentation of the hydrogen chain were also identified as hurdles. However, it was also acknowledged that the narrative around hydrogen is evolving positively and rapidly, with RES-based hydrogen especially seen as a key tool to reach net-zero emissions.

Within the LNG industry, different actors will respond to hydrogen development differently. 2040 and 2050 are beyond the average life of current LNG projects, the life of ship leases and other related facilities. This may even be the case for projects that will be financed and developed in the coming five years. However, for resource owners, especially in countries where gas revenue represents a significant source of income, the slow but then rapid development of hydrogen demand presents a potential long-term risk for their natural gas exports. Increasing investment into natural gas-based hydrogen production and CCUS technology and expanding LNG import terminals to explore synergies with industrial clusters are measures that can be taken to ensure that future strategies are in line with deep decarbonisation policies. In addition, steps to "clean up" the LNG value chain (fugitive emissions, liquefaction-related emissions) should be taken in order to meet the more stringent emission reduction criteria associated with a progressive decarbonisation of the energy system. A long-term low-carbon strategy provides an opportunity for LNG resource owners to support their host governments' diversification plans by increasing the ability to monetise their natural gas reserves while maintaining access to high-value markets.

As the hydrogen industry develops while the LNG industry continues to play a significant role in the global energy system, the link between the two is important. As Hanley et al. (2015, p. 56) conclude, "it is evident that the links between natural gas and hydrogen are very long standing and are likely to grow, not diminish, in the coming years."

Table 3 summarises and expands on the wider set of strategic choices pertaining to low-carbon hydrogen discussed in this paper and outlines their consequences for LNG exporters.

Table 3: Impact of strategic choices with respect to hydrogen on LNG exporters

<table>
<tr><th colspan="3">Strategic choices</th><th rowspan="2">Impact on LNG exporters</th></tr>
<tr><th>Value chain options</th><th>Natural gas</th><th>Renewable energy</th></tr>
<tr><td>Production technology</td><td>Natural gas reforming or pyrolysis.</td><td>Electrolysis.</td><td>• NGR+CCUS and/or pyrolysis in the importing country could present upside for natural gas demand; LNG exporters can play a direct role by delivering the natural gas feedstock needed.
• RES-based hydrogen would be a downside for natural gas demand, minimal opportunities for LNG exporters in green pathways.</td></tr>
<tr><td rowspan="2">Production location</td><td>Domestic gas to be converted to hydrogen.</td><td>Hydrogen produced via renewable energy and electrolysers domestically.</td><td rowspan="2">• LNG exporters could convert natural gas into hydrogen at LNG receiving terminal, subject to CCUS access or methane pyrolysis technology.
• For hydrogen import-based strategies, limited direct role for LNG; exporters can potentially leverage know-how and commercial links, potentially retrofitting export terminal and some facilities.
• For pure non-import strategies, there is no role for LNG exporters.</td></tr>
<tr><td>LNG to be imported and converted to hydrogen near LNG importing terminal.</td><td>RES-based hydrogen imported via liquid hydrogen, liquid organic hydrogen carriers, ammonia (or other derivatives).</td></tr>
<tr><td rowspan="2">Hydrogen transport (pure hydrogen vs derivatives)</td><td>Natural gas can be converted to pure hydrogen with NGR+CCUS, or pyrolysis.</td><td>Pure hydrogen produced via low-carbon renewable energy.</td><td rowspan="2">• Utilising current LNG infrastructure and import terminal allows for LNG to be shipped and converted into hydrogen at importing countries.
• Pure hydrogen, and all other derivatives except synthetic methane have separate technical requirements for liquefaction/loading, shipping, and receiving infrastructure, limited scope for LNG exporters.</td></tr>
<tr><td>Natural gas-based hydrogen could be converted into synthetic methanol, methane, Fischer-Tropsch liquid hydrocarbons, ammonia, etc.</td><td>RES-based hydrogen could be converted into synthetic methanol, methane, Fischer-Tropsch liquid. hydrocarbons, ammonia, etc.</td></tr>
<tr><td rowspan="2">Hydrogen end-use (targeted vs economy-wide)</td><td>Natural gas-based hydrogen to target applications, such as chemical feedstock, oil refining, steel production, ammonia production; initially replace current / potential hydrogen demand.</td><td>RES-based hydrogen to target applications such as chemical feedstock, oil refining, steel production, ammonia production; initially replace current hydrogen demand. In the long run, it is likely that processes will relocate to areas with high-RES demand.</td><td rowspan="2">• LNG terminals located near industrial clusters present an opportunity to take advantage of technical and commercial synergies.
• For wide-scale hydrogen adoption, importers could leverage existing gas infrastructure by blending and other measure in the medium term. LNG exporters long term role will depend on the ability to manage CO_2 (CCUS or pyrolysis), and favourable government policy.
• Countries may take political decisions to utilise only RES-based hydrogen, which would limit LNG exporters' role drastically.</td></tr>
<tr><td>Natural gas-based hydrogen's role in large scale hydrogen adoption will depend on technical characteristics, economics, and government policy.</td><td>RES-based hydrogen's role in large scale hydrogen adoption will depend on available renewable resources, economics, and government policy.</td></tr>
<tr><td rowspan="2">Hydrogen role (exports vs domestic use)</td><td>Natural gas-based hydrogen supports exports to sectors and countries with increasing hydrogen demand.</td><td>RES-based hydrogen allows for countries with rich renewable energy resources the ability to export a new commodity, subject to geographical location and technological improvements.</td><td rowspan="2">• LNG exporters could continue to export to end-users with aggressive decarbonisation targets.
• Longer term, LNG exporters who are resource owners may consider shifting to exporting hydrogen derivatives (reforming natural gas and managing carbon domestically), altering entire value chain.</td></tr>
<tr><td>Natural gas-based hydrogen could decarbonise current domestic hydrogen and other derivatives demand.</td><td>RES-based hydrogen could decarbonise current domestic hydrogen and other derivatives demand.</td></tr>
</table>

Source: interviews and own analysis, table adapted from Van de Graaf et al. (2020).

3.3. Limitations and Further Research

It should be noted that there are some limitations to the model-based analysis presented in this paper. Firstly, we do not explicitly model the production, transportation and consumption of hydrogen-based synthetic fuels and feedstocks such as ammonia or methanol separately from hydrogen. As mentioned above, producing and exporting such energy carriers might be an opportunity for producers with low-cost RES in scenarios where hydrogen production is predominantly RES-based.

Furthermore, existing commercial relationships, strategic considerations and policy choices may play an important role in shaping the evolution of the market for low-carbon hydrogen as well, which are not easily represented in models such as the one used in the paper at hand. This was highlighted by interviewees, who noted that the development of a technology mix, taking advantage of supply economics, regulatory support, and technological improvements, is what is likely to unfold. In addition, the fragmented nature of hydrogen with complex supply chains that can be structured in a variety of derivatives and end-uses, coupled by the different approaches of the prominent energy players, likely will lead to different routes being developed, and therefore different technology combinations. As an industry participant concluded: "different places will get different solutions."

This opens avenues for further research. For example, a more detailed representation of other relevant hydrogen-derived energy carriers in a global model could be used to explore potential alternative business models based on the production and export of such energy carriers rather than hydrogen.

Additionally, future research may look at the actual implementation of export-oriented business models centred on hydrogen, for example, potential contractual frameworks required to establish such a business.

Finally, expanding the outlook to the period beyond 2050 may provide further insight into the economic implications of increased hydrogen use on LNG exporting countries in a net-zero emissions economy (i.e. potential for stranded assets).

4. Conclusions

We perform a model-based scenario analysis to quantify the impact of different global low-carbon hydrogen development pathways on LNG exporters using a novel, integrated natural gas and hydrogen market model. The scenarios are based on recent projections by the International Energy Agency (IEA) and consistent with a deep decarbonisation of the global energy system by 2050.

We find that low-carbon hydrogen production has the potential to become a significant user of natural gas by 2040, stabilising global natural gas consumption within a framework of global decarbonisation. In scenarios where different low-carbon hydrogen production technologies compete on cost, natural gas-based pathways predominate. The exception is regions with very good RES potentials in scenarios where RES and electrolyser investment costs decline substantially compared to the baseline. However, even in such cases, the cost margin between natural gas- and RES-based low-carbon hydrogen production technologies is relatively narrow. This is an effect of natural gas prices remaining at comparably low levels due to overall stagnation in global natural gas demand. The development of pyrolysis as a potentially less costly alternative to NGR with CCUS could further reinforce the economic advantage of natural-gas based hydrogen production in such a low gas price environment. In scenarios with high shares of natural gas-based hydrogen production, LNG demand continues to grow to 2050. In scenarios where RES-based hydrogen becomes the dominant pathway globally, LNG demand grows until 2040 and then declines. In conclusion, LNG demand is generally resilient in technology-agnostic scenarios, even as global demand for natural gas decreases.

The results suggest that for LNG exporters, encouraging the adoption of natural-gas based low-carbon hydrogen in import markets appears to be a viable strategy to safeguard export revenues. LNG industry participants interviewed for the paper at hand acknowledged the growing importance of low-carbon hydrogen and identified hydrogen as both an opportunity and a threat in the long term. Furthermore, the LNG industry is perceived to be well-positioned in terms of skills and resources to play a role in developing low-carbon hydrogen, mainly due to its large-scale engineering and project management capabilities. Rather than technical, the most relevant synergies between LNG and low-carbon hydrogen appear to be commercial. The LNG industry has decades of experience developing specialised infrastructure and supply chains, with associated high investment risks and high capital requirements. The initial development of LNG-based low-carbon hydrogen supply chains could be modelled on the LNG market, with long-term off-take agreements centred on industrial clusters built around LNG import terminals.

Acknowledgements

Financial support for this research by the "Research Programme Hydrogen: The Role of Gas in the Energy Transition", an initiative of the Society of Benefactors to the EWI (Gesellschaft zur Förderung des EWI e.V) is gratefully acknowledged. We thank Michael Grubb, Professor of Energy and Climate Change and Professor Albert Bressand, Bartlett School of Environment, Energy and Resources at the Institute for Sustainable Resources, University College London (UCL) and Marc Oliver Bettzüge, Professor of Energy Economics and director of the Institute of Energy Economics at the University of Cologne (EWI), for their valuable guidance and support. We are also grateful to Gregor Brändle and Simon Schulte for their suggestions and feedback.

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Appendix A. Interviews

Questions:

- How do you think the evolution of hydrogen will impact the LNG industry?

  Short and long term?

  Regionally?

- Is hydrogen development a threat or opportunity for LNG?
- What options exist for the LNG industry in natural gas-based (blue) and RES-based (green) hydrogen pathways?
- Focusing on Qatar LNG and Australian LNG, how do you see hydrogen market evolution impacting them specifically?

Interviewees:

1. Executive – International oil company, major LNG player
2. Executive – International oil company, major LNG player
3. Analyst – Major international organisation
4. Senior Analyst – Major international organisation
5. Partner – Management consultancy
6. Executive – LNG and decarbonisation expert
7. Executive – LNG marketing, production and trading
8. Executive – LNG marketing, trading

Appendix B. Additional Assumptions

Table B.4: Country-specific CO_2 storage cost and WACC used in the model

Country	CO_2 storage assumptions			WACC
	Formation	Location	Cost ($/t$CO_2$)	
Algeria	Depleted oil & gas field	Onshore	17.6	12.8%
Angola	Depleted oil & gas field	Offshore	23.3	11.3%
Egypt	Depleted oil & gas field	Onshore	17.6	16.1%
Equatorial Guinea	Depleted oil & gas field	Offshore	23.3	10.8%
Libya	Depleted oil & gas field	Onshore	17.6	12.8%
Nigeria	Depleted oil & gas field	Onshore	17.6	10.8%
Ghana	Depleted oil & gas field	Offshore	23.3	12.9%
Morocco	Saline formations	Onshore	23.4	9.4%
Tunisia	Depleted oil & gas field	Onshore	17.6	10.7%
Mozambique	Depleted oil & gas field	Offshore	23.3	11.7%
Australia	Depleted oil & gas field	Onshore	17.6	8.4%
Brunei Darussalam	Depleted oil & gas field	Offshore	23.3	9.5%
Indonesia	Depleted oil & gas field	Onshore	17.6	10.4%
Malaysia	Depleted oil & gas field	Offshore	23.3	9.5%
Myanmar	Depleted oil & gas field	Offshore	23.3	11.7%
Bangladesh	Depleted oil & gas field	Offshore	23.3	11.7%
China	Saline formations	Onshore	23.4	9.0%
India	Depleted oil & gas field	Onshore	17.6	10.7%
Japan	Saline formations	Offshore	36.2	8.6%
Korea	Saline formations	Onshore	23.4	8.8%
Philippines	Depleted oil & gas field	Offshore	23.3	10.0%
Pakistan	Depleted oil & gas field	Onshore	17.6	15.7%
Singapore	Depleted oil & gas field	Offshore	23.3	8.6%
Thailand	Depleted oil & gas field	Offshore	23.3	9.7%
Taiwan	Saline formations	Offshore	36.2	9.0%
Vietnam	Depleted oil & gas field	Offshore	23.3	12.1%
Azerbaijan	Depleted oil & gas field	Offshore	23.3	9.1%
Kazakhstan	Depleted oil & gas field	Onshore	17.6	10.2%
Russian Federation	Depleted oil & gas field	Onshore	17.6	10.2%
Turkmenistan	Depleted oil & gas field	Onshore	17.6	10.2%
Uzbekistan	Depleted oil & gas field	Onshore	17.6	10.2%
Ukraine	Saline formations	Onshore	23.4	14.8%
Georgia	Saline formations	Onshore	23.4	9.8%
Denmark	Depleted oil & gas field	Offshore	23.3	7.1%
Netherlands	Depleted oil & gas field	Offshore	23.3	7.3%
Norway	Depleted oil & gas field	Offshore	23.3	7.2%
United Kingdom	Depleted oil & gas field	Offshore	23.3	8.4%
Austria	Saline formations	Onshore	23.4	7.2%
Baltic States	Saline formations	Onshore	23.4	7.9%
Belgium	Saline formations	Onshore	23.4	7.8%
Bulgaria	Depleted oil & gas field	Offshore	23.3	8.6%
Belarus	Saline formations	Onshore	23.4	16.2%
Switzerland	Saline formations	Onshore	23.4	7.2%
Czech Republic	Saline formations	Onshore	23.4	7.8%
Germany	Depleted oil & gas field	Offshore	23.3	7.1%
Spain	Saline formations	Onshore	23.4	8.7%
Finland	Saline formations	Onshore	23.4	7.3%
France	Saline formations	Onshore	23.4	7.4%
Greece	Saline formations	Onshore	23.4	13.3%
Hungary	Saline formations	Onshore	23.4	9.1%
Ireland	Saline formations	Onshore	23.4	8.5%
Italy	Saline formations	Onshore	23.4	8.6%
Poland	Saline formations	Onshore	23.4	8.0%
Portugal	Saline formations	Onshore	23.4	9.3%
Romania	Depleted oil & gas field	Offshore	23.3	9.0%
Sweden	Saline formations	Onshore	23.4	7.1%
Slovenia	Saline formations	Onshore	23.4	9.2%

Slovakia	Saline formations	Onshore	23.4	8.0%
Turkey	Depleted oil & gas field	Offshore	23.3	9.2%
Moldova	Depleted oil & gas field	Offshore	23.3	13.2%
Yugoslavia	Saline formations	Onshore	23.4	9.2%
Argentina	Depleted oil & gas field	Onshore	17.6	16.1%
Bolivia	Depleted oil & gas field	Onshore	17.6	11.5%
Peru	Depleted oil & gas field	Onshore	17.6	9.5%
Trinidad and Tobago	Depleted oil & gas field	Offshore	23.3	11.5%
Venezuela	Depleted oil & gas field	Offshore	23.3	20.5%
Brazil	Depleted oil & gas field	Onshore	17.6	10.1%
Chile	Saline formations	Onshore	23.4	9.0%
Colombia	Depleted oil & gas field	Onshore	17.6	9.7%
Caribbean	Depleted oil & gas field	Offshore	23.3	8.3%
Iran	Depleted oil & gas field	Offshore	23.3	9.2%
Iraq	Depleted oil & gas field	Onshore	17.6	10.2%
Oman	Depleted oil & gas field	Onshore	17.6	9.1%
Qatar	Depleted oil & gas field	Offshore	23.3	8.4%
Saudi Arabia	Depleted oil & gas field	Onshore	17.6	9.2%
United Arab Emirates	Depleted oil & gas field	Onshore	17.6	8.4%
Yemen	Depleted oil & gas field	Onshore	17.6	20.5%
Bahrain	Depleted oil & gas field	Onshore	17.6	8.4%
Kuwait	Depleted oil & gas field	Onshore	17.6	8.9%
Syria	Depleted oil & gas field	Onshore	17.6	20.5%
Near East	Depleted oil & gas field	Offshore	23.3	12.8%
Canada	Depleted oil & gas field	Onshore	17.6	8.3%
United States	Depleted oil & gas field	Onshore	17.6	8.1%
Mexico	Depleted oil & gas field	Onshore	17.6	9.4%
South Africa	Saline formations	Onshore	23.4	10.0%
Iceland	Saline formations	Onshore	23.4	8.5%
Papua New Guinea	Depleted oil & gas field	Onshore	17.6	11.8%
Cameroon	Depleted oil & gas field	Offshore	23.3	11.6%

CO_2 storage costs are calculated based on Roussanaly et al. (2014) and Rubin et al. (2015). We assume an average distance of 200 km between production sites and storage reservoirs and a connection by CO_2 pipeline.
WACC = weighted average cost of capital. Country-specific WACC figures (corresponding to oil & gas sector risk-return profiles) are taken from Finance 3.1 (2021), supplemented by own assumptions.

Appendix C. Mathematical Description of the Model

This section provides are more detailed mathematical description of the combined natural gas and low-carbon hydrogen market model used in the paper at hand. It is taken from Schönfisch (2021).

Model Structure

The time structure of the model is given by a set $t \subset T$ of points in time. Spatially, the model is defined by a set of nodes $n \subset N$ which are connected through arcs $n \rightarrow n1$. Nodes are divided into natural gas and hydrogen production, liquefaction, regasification and consumption nodes, and the arcs connecting them represent pipelines and LNG/LH_2 shipping routes.

The model is populated by different profit-maximising agents: exporters, producers, transmission system operators (TSOs), liquefiers, regasifiers and shippers. Subject to various constraints, they maximise their profits by making optimal decisions with respect to the production, sale and transport of natural gas or hydrogen; and through optimal investments into production and transportation infrastructure.

The respective optimisation problems of the individual agents situated along the natural gas and hydrogen value chains and their corresponding first-order optimality conditions are outlined in the following subsections. The partial equilibrium model is formed by combining the first-order optimality conditions with the market clearing conditions of the respective markets.

The Exporter's Problem

Exporters $e \in E$ sell natural gas and/or hydrogen $f \in F = \{H_2, NG\}$ to consumers. They are affiliated with at least one natural gas or hydrogen production node $p \in P$. They purchase fuel from associated production nodes and sell ($sell_{e,f,d,t}$) it to consumers located in consumption nodes $d \in D$. The exporter's payoff function is the following:

$$\begin{aligned} &\max_{sell_{e,f,d,t}} \prod_{eI}(sell_{e,f,d,t}) \\ &= \sum_{t}\sum_{d}\Big((1-cv_e)*\beta_{f,d,t} + cv_e*\beta_{f,d,t}(\sum_{e} sell_{e,f,d,t}) - \lambda_{e,f,d,t}\Big)*sell_{e,f,d,t}, \qquad \text{(C.1)} \\ &sell_{e,f,d,t} \geq 0 \end{aligned}$$

where $\lambda_{e,f,d,t}$ corresponds to the cost associated with production and delivery of the respective fuel f to a consumption node d and $\beta_{f,d,t}$ is the market price for fuel f at consumption node d. The conjectural variation parameter cv_e determines whether a exporter is able to exert market power or behaves as a price taker. If $cv_e = 1$, the exporter faces a linear inverse demand function and thus implicitly considers the impact of its own sales and those of others on the market price $\beta_{f,d,t}$. Otherwise, if $cv_e = 0$, it observes market price directly and behaves as a price taker.

On the natural gas market, long-term contracts (LTCs) play an important role in determining trade flows. They are modelled as a constraint, which ensures that an exporter's sales to consumers with which a long-term contract is in place are always equal or greater than the contractually defined minimum delivery obligation ($mdo_{e,f,d,t}$):

$$\sum_{t} sell_{e,f,d,t} - mdo_{e,f,d,t} \geq 0 \qquad \forall \;\; e,f,d,t \qquad (\chi_{e,f,d,t}) \tag{C.2}$$

The first-order optimality condition of the exporter's profit maximisation problem is defined by the first partial derivative of the Lagrangian $\mathcal{L}_{eI}$ with respect to the variable $sell_{e,f,d,t}$:

$$\begin{aligned} -\beta_{f,d,t} + (cv_e + 1) * \text{slope}_{f,d,t} * sell_{e,f,d,t} - \chi_{e,f,d,t} + \lambda_{e,f,d,t} \geq 0 \\ \perp \quad sell_{e,f,d,t} \geq 0 \qquad \forall \;\; e,f,d,t. \end{aligned} \tag{C.3}$$

Sales have to be matched by actual physical deliveries of natural gas or hydrogen. This is modelled as a separate optimisation problem:

$$\begin{aligned} &\max_{flow_{e,f,n,n1,t}} \prod_{eII}(flow_{e,f,n,n1,t}) \\ &= \sum_{t}(\lambda_{e,f,n1,t} - \lambda_{e,f,n,t} - varcost^{tra}_{f,n,n1,t} - varcost^{tra}_{f,r,t}) * flow_{e,f,n,n1,t} \end{aligned} \tag{C.4}$$

Exporters choose the least-cost supply route ($flow_{e,f,n,n1,t}$) to fulfil their delivery obligation, where $\lambda_{e,f,n,t}$ is the marginal cost of gas supplied by exporter s to node n and $\lambda_{e,f,n1,t}$ is the marginal cost of gas or hydrogen delivered by s to node $n1$. $varcost^{tra}_{f,r,t}$ is the cost of regasifying a unit of natural gas or hydrogen if n is a regasification node $[r(n)]$, while $varcost^{tra}_{f,n,n1,t}$ is the short-run marginal cost of transporting natural gas or hydrogen from node n to node $n1$. If $n1$ is a liquefaction node $[l(n1)]$, $varcost^{tra}_{f,n,l,t}$ is equivalent to the short-run marginal cost of liquefying the commodity. If n and $n1$ are connected by pipeline, $varcost^{tra}_{f,n,n1,t}$ denotes the short-run marginal cost of pipeline deliveries. Finally, if the node pair are a liquefaction node $[l(n)]$ and a regasification node $[r(n1)]$, $varcost^{tra}_{f,l,r,t}$ expresses the short-run marginal cost of transporting the respective commodity f by tanker.

The transportation problem expressed in Equation C.4 is subject to physical capacity constraints. Equation C.5 describes the pipeline capacity constraint, with total pipeline capacity given by the sum of exogenous capacity ($cap^{pipe}_{f,n,n1,t}$) and additional, endogenous investments ($inv^{pipe}_{f,n,n1,t}$):

$$cap^{pipe}_{f,n,n1,t} + inv^{pipe}_{f,n,n1,t} - \sum_{e} flow_{e,f,n,n1,t} \geq 0 \qquad \forall \;\; f,n,n1,t \qquad (\phi_{f,n,n1,t}) \tag{C.5}$$

Equations C.6, C.7 and C.8 outline the liquefaction, regasification and shipping capacity constraints, respectively. The maximum available shipping capacity on a given route is derived taking into account the average capacity of an LNG or LH_2 tanker (cap^{ship}_{f}), the number of vessels invested in ($inv^{ship}_{f,t}$), their average speed in km/h ($speed$) and the round-trip distance ($dist_{l,r}$).

$$cap^{liq}_{f,l,t} + inv^{liq}_{f,l,t} - \sum_{e}\sum_{n} flow_{e,f,n,l,t} \geq 0 \qquad \forall\ f,l,t \qquad (\zeta_{f,l,t}) \tag{C.6}$$

$$cap^{reg}_{f,r,t} + inv^{reg}_{f,r,t} - \sum_{e}\sum_{d} flow_{e,f,r,d,t} \geq 0 \qquad \forall\ f,r,t \qquad (\gamma_{f,r,t}) \tag{C.7}$$

$$\begin{aligned} &\left(cap^{ship}_{f} * inv^{ship}_{f,t}\right) * 8760/12 * speed \\ &- \sum_{e}\sum_{l}\sum_{r} 2 * (flow_{e,f,l,r,t} * dist_{l,r}) \geq 0 \qquad \forall\ f,t \qquad (\iota_{f,t}) \end{aligned} \tag{C.8}$$

The associated first-order condition of the transportation problem defined in Equation C.4 is derived by taking the first partial derivative of the Lagrangian $\mathcal{L}_{eII}$ with respect to the variable $flow_{e,f,n,n1,t}$:

$$\begin{aligned} &- \lambda_{e,f,n1,t} + \lambda_{e,f,n,t} + varcost^{tra}_{f,n,n1,t} + varcost^{tra}_{f,r,t} + \phi_{f,n,n1,t} \\ &+ \zeta_{f,l,t} + \gamma_{f,r,t} + \iota_{f,t} * 2 * dist_{l,r} \geq 0 \quad \perp \quad flow_{e,f,n,n1,t} \geq 0 \qquad \forall\ e,f,n,n1,t. \end{aligned} \tag{C.9}$$

The Producer's Problem

Producers operate a single production node $p \in P$ and maximise their profits by selling natural gas or hydrogen to their affiliated exporter e. They act as price takers, which means that in essence, producer and exporter together behave like a single, vertically integrated firm. The producer payoff functions differ slightly depending on the fuel that is produced and—in the case of hydrogen—the production pathway that is chosen.

Natural gas production is modelled as a piecewise linear supply function with $c \subset C$ cost steps, which reflects the short-run marginal cost of existing production and the long-run marginal cost of prospective developments. The producer payoff function for natural gas is given by Equation C.10, where $\lambda_{e,NG,p,t}$ is the marginal value of gas in production node p, $prod_{NG,c,p,t}$ is the production volume of natural gas and $varcost^{prod}_{NG,p,c,t}$ the marginal production cost:

$$\max_{prod_{NG,p,c,t}} \prod_{pI} (prod_{NG,p,c,t}) = \sum_{t}\sum_{c} (\lambda_{e,NG,p,t} * prod_{NG,c,p,t} - varcost^{prod}_{NG,p,c,t} * prod_{NG,p,c,t}) \tag{C.10}$$

Equation C.11 describes the payoff function of hydrogen producers. The model considers both RES- and natural gas-based low-carbon hydrogen production pathways. For hydrogen, investment decisions are modelled explicitly. Producers can therefore invest into additional production capacity ($inv^{prod}_{H2,p,c,t}$), incurring investment costs ($invcost^{prod}_{H2,p,c,t}$). Here, $c \subset C$ stands for different hydrogen production pathways. The term $purch_{p,t} * \beta_{NG,p,t}$ is specific to natural gas-based hydrogen production and expresses the opportunity cost of purchasing natural gas for hydrogen production, with $\beta_{NG,p,t}$ denoting the price of natural gas in the respective production node:

$$\max_{\substack{prod_{H2,p,c,t}\\ inv^{prod}_{H2,p,c,t}}} \prod_{pII} (prod_{H2,p,c,t}, inv^{prod}_{H2,p,c,t})$$
$$= \sum_t \sum_c (\lambda_{e,H2,p,t} * prod_{H2,c,p,t} - varcost^{prod}_{H2,p,c,t} * prod_{H2,p,c,t} - purch_{p,t} * \beta_{NG,p,t}) \tag{C.11}$$
$$+ \sum_t \sum_c (invcost^{prod}_{H2,p,c,t} * inv^{prod}_{H2,p,c,t})$$

The producers are subject to capacity and—in the case of RES-based hydrogen—availability constraints. Natural gas production is limited to the maximum production capacity ($cap^{prod}_{NG,p,c,t}$) of the respective cost step c (Equation C.12).

$$cap^{prod}_{NG,p,c,t} - prod_{NG,c,p,t} \geq 0 \qquad \forall\ p, c, t \qquad (\mu_{NG,p,c,t}) \tag{C.12}$$

Hydrogen production is limited by the installed capacity, including endogenous investments ($cap^{prod}_{NG,p,c,t} + inv^{prod}_{H2,p,c,t}$). RES-based hydrogen production is further constrained by the capacity factor ($cf^{prod}_{H2,c,p,t}$) of the respective renewable energy source (Equation C.13). The capacity factors are calculated for cost-optimal combinations of a renewable energy source and an electrolyser, taking into account the full cost of both components, as well as differences in the quality and variability of the RES in the 89 countries covered by the model. A detailed description of the underlying methodology and estimates is provided in Brändle et al. (2021).

$$(cap^{prod}_{H2,p,c,t} + inv^{prod}_{H2,p,c,t}) * cf^{prod}_{H2,c,p,t} - prod_{H2,c,p,t} \geq 0 \qquad \forall\ p, c, t \qquad (\mu_{H2,p,c,t}) \tag{C.13}$$

As shown in Equation C.14, natural gas-based hydrogen production technologies $[ngb(c)]$ are further constrained by the amount of natural gas purchased for hydrogen production ($purch_{p,ngb,t}$) in the respective production node p, which must be equal or greater than the amount of hydrogen produced ($prod_{H2,p,ngb,t}$), divided by the process efficiency ($eff^{prod}_{H2,p,ngb,t}$).

$$purch_{p,ngb,t} - \frac{prod_{H2,p,ngb,t}}{eff^{prod}_{H2,p,ngb,t}} \geq 0 \qquad \forall\ p, ngb \subset C, t \qquad (\omega_{p,ngb,t}) \tag{C.14}$$

The first-order optimality condition of the natural gas producer's maximisation problem (Equation C.10) is given by the partial derivative of the Lagrangian $\mathcal{L}_{pI}$ with respect to the variable $prod_{NG,p,c,t}$:

$$-\lambda_{e,NG,p,t} + varcost^{prod}_{NG,p,c,t} + \mu_{NG,p,c,t} \geq 0 \quad \perp \quad prod_{NG,p,c,t} \geq 0 \qquad \forall\ f, p, c, t \tag{C.15}$$

Finally, the first-order conditions of the hydrogen producer's maximisation problem (Equation C.11) are derived by taking the partial derivatives of the Lagrangian $\mathcal{L}_{pI}$ with respect to the variables $prod_{H2,p,c,t}$, $purch_{p,t}$ and $inv^{prod}_{H2,p,c,t}$:

$$-\lambda_{e,H2,p,t} + varcost^{prod}_{H2,p,c,t} + \mu_{H2,p,c,t} + \omega_{p,t} \geq 0 \quad \perp \quad prod_{H2,p,c,t} \geq 0 \qquad \forall \ f,p,c,t \tag{C.16}$$

$$-\omega_{p,ngb,t} + \beta_{NG,p,t} \geq 0 \quad \perp \quad purch_{p,ngb,t} \geq 0 \qquad \forall \ f,p,t \tag{C.17}$$

$$invcost^{prod}_{H2,p,c,t} - \mu_{H2,p,c,t} \geq 0 \quad \perp \quad inv^{prod}_{H2,p,c,t} \geq 0 \qquad \forall \ p,c,y \tag{C.18}$$

The Transmission System Operator's Problem

TSOs are players that control pipeline arcs ($n \rightarrow n1$). They allocate transmission capacity to exporters and are in turn compensated for the short-run marginal cost of transmission ($varcost^{tra}_{f,n,n1,t}$)[10] and the congestion rent ($\phi_{f,n,n1,t}$), which is determined by the transmission capacity constraint (Equation C.5). TSOs invest into additional pipeline capacity if the long-run marginal cost of transmission expansion is less than the congestion rent. Their payoff function is as follows:

$$\begin{aligned} &\max_{inv^{pipe}_{f,n,n1,t}} \prod_{TSO} (inv^{pipe}_{f,n,n1,t}) \\ &= \sum_{t} \left[\phi_{f,n,n1,t} * (cap^{pipe}_{f,n,n1,t} + inv^{pipe}_{f,n,n1,t}) \right] - inv^{pipe}_{f,n,n1,t} * invcost^{pipe}_{f,n,n1,t} \end{aligned} \tag{C.19}$$

Taking the partial derivative of the Lagrangian $\mathcal{L}_{TSO}$ with respect to the variable $inv^{pipe}_{f,n,n1,t}$ yields the first-order optimality condition:

$$invcost^{pipe}_{f,n,n1,t} - \phi_{f,n,n1,t} \geq 0 \quad \perp \quad inv^{pipe}_{f,n,n1,t} \geq 0 \qquad \forall \ f,n,n1,t. \tag{C.20}$$

The Liquefier's Problem

Liquefiers (l) receive natural gas or hydrogen and liquefy it. They allocate liquefaction capacity to exporters and in exchange for the short-run liquefaction cost ($varcost^{tra}_{f,n,l,t}$) and the congestion rent ($\zeta_{f,l,t}$). The congestion rent is determined by the liquefaction capacity constraint (Equation C.6). They maximise their payoff in accordance with Equation C.21:

$$\max_{inv^{liq}_{f,l,t}} \prod_{l} (inv^{liq}_{f,l,t}) = \sum_{t} \left[\zeta_{f,l,t} * (cap^{liq}_{f,l,t} + inv^{liq}_{f,l,t}) \right] - inv^{liq}_{f,l,t} * invcost^{liq}_{f,l,t} \tag{C.21}$$

Their first-order optimality condition is:

$$invcost^{liq}_{f,l,t} - \zeta_{f,l,t} \geq 0 \quad \perp \quad inv^{liq}_{f,l,t} \geq 0 \qquad \forall \ f,l,t. \tag{C.22}$$

The Regasifier's Problem

[10] Which thus cancels out in the payoff function.

Regasifiers (r) receive LNG or LH_2 and regasify it. They allocate regasification capacity to exporters, who pay for the short-run regasification cost ($varcost^{tra}_{f,r,t}$) and the congestion rent ($\gamma_{f,r,t}$). The congestion rent is determined by the regasification capacity constraint (Equation C.7). Their payoff function is described by Equation C.23:

$$\max_{inv^{reg}_{f,r,t}} \prod_{r}(inv^{reg}_{f,r,t}) = \sum_{t} \left[\gamma_{f,r,t} * (cap^{reg}_{f,r,t} + inv^{reg}_{f,r,t})\right] - inv^{reg}_{f,r,t} * invcost^{reg}_{f,r,t} \tag{C.23}$$

Their first-order optimality condition is:

$$invcost^{reg}_{f,r,t} - \gamma_{f,r,t} \geq 0 \quad \perp \quad inv^{reg}_{f,r,t} \geq 0 \qquad \forall\ f, r, t. \tag{C.24}$$

The Shipper's Problem

The market for LNG or LH_2 shipping capacity is modelled as a single player (shipper) who behaves competitively. The shipper allocates shipping capacity to exporters, passing on operating costs ($varcost^{tra}_{f,l,r,t}$) and congestion rent ($\iota_{f,t}$). The shipper invests into additional shipping capacity until the associated long-run marginal cost exceeds the congestion rent, which is determined by the shipping capacity constraint (Equation C.8). Its payoff function is given by Equation C.25:

$$\begin{aligned}&\max_{inv^{ship}_{f,t}} \prod_{LNG}(inv^{ship}_{f,t}) \\ &= \sum_{t} \left[\iota_{f,t} * 8760/12 * speed * (cap^{ship}_{f} * inv^{ship}_{f,t})\right] - inv^{ship}_{f,t} * invcost^{ship}_{f,t}\end{aligned} \tag{C.25}$$

The first-order optimality condition is derived by taking the partial derivative of Lagrangian $\mathcal{L}_{LNG}$ with respect to $inv^{ship}_{f,t}$:

$$invcost^{ship}_{f,t} - \iota_{f,t} * 8760/12 * speed \geq 0 \quad \perp \quad inv^{ship}_{f,t} \geq 0 \qquad \forall\ f, t. \tag{C.26}$$

Market Clearing Conditions

The first-order optimality conditions of the individual optimisation problems described above, together with the following market clearing conditions, comprise the partial equilibrium model.

Equation C.27 ensures that trades ($sale_{e,f,d,t}$) are matched by production and/or net inflows:

$$\begin{aligned}&\sum_{c} prod_{f,p,c,t} - sell_{e,f,d,t} + \sum_{n1\in(n1,n)} flow_{e,f,n1,n,t} - \sum_{n1\in(n,n1)} flow_{e,f,n,n1,t} = 0 \\ &\perp \quad \lambda_{e,f,n,t} \quad \text{free} \qquad \forall\ e, f, n, t.\end{aligned} \tag{C.27}$$

Equations C.28 (for natural gas) and C.29 (for hydrogen) assure that aggregate sales ($sell_{e,f,n,t}$) match demand ($dem_{f,d,t}$) and, in the case of natural gas, gas purchases for hydrogen production ($purch_{p,ngb,t}$). The dual variable ($\beta_{f,n,t}$) can be interpreted as the market price of the respective fuel:

$$\sum_{e} sell_{e,NG,d,t} - dem_{NG,d,t} - \sum_{ngb \in (C)} purch_{p,ngb,t} = 0 \quad \perp \quad \beta_{NG,d,t} \quad \text{free} \qquad \forall \;\; f,d,t. \tag{C.28}$$

$$\sum_{e} sell_{e,H2,d,t} - dem_{H2,d,t} = 0 \quad \perp \quad \beta_{H2,d,t} \quad \text{free} \qquad \forall \;\; f,d,t. \tag{C.29}$$

Appendix D. Supplementary Model Results

Table D.5: Projected annual trade flows on the LNG market (in bcm)

FROM/TO	Scenario	Africa			Asia Pacific			CIS			Europe			Middle East			Latin America			North America			Total		
		2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
Africa	OPT (baseline)	0	24	19	44	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	44	44	40
	OPT (low cost)	0	24	20	45	20	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	44	38
	OPT (low cost/pyrolysis)	0	34	49	45	19	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	53	104
	GRT (baseline)	0	10	23	46	32	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	46	42	36
Asia Pacific	OPT (baseline)	0	0	0	134	148	131	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	134	148	131
	OPT (low cost)	0	0	0	134	148	112	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	134	148	112
	OPT (low cost/pyrolysis)	0	0	0	136	147	136	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	136	147	136
	GRT (baseline)	0	0	0	137	147	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137	147	60
CIS	OPT (baseline)	0	0	0	49	65	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	49	65	68
	OPT (low cost)	0	0	0	50	65	66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	65	66
	OPT (low cost/pyrolysis)	0	0	0	48	73	79	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	73	79
	GRT (baseline)	0	0	0	63	64	63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	63	64	63
Europe	OPT (baseline)	0	0	0	0	0	0	0	0	0	6	6	6	0	0	0	0	0	0	0	0	0	6	6	6
	OPT (low cost)	0	0	0	0	0	0	0	0	0	6	6	6	0	0	0	0	0	0	0	0	0	6	6	6
	OPT (low cost/pyrolysis)	0	0	0	0	0	0	0	0	0	6	6	6	0	0	0	0	0	0	0	0	0	6	6	6
	GRT (baseline)	0	0	0	0	0	0	0	0	0	6	5	5	0	0	0	0	0	0	0	0	0	6	5	5
L. America	OPT (baseline)	0	0	0	5	3	4	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	7	4	4
	OPT (low cost)	0	0	0	5	5	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	7	6	0
	OPT (low cost/pyrolysis)	0	0	0	5	5	4	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	7	5	4
	GRT (baseline)	0	0	0	5	6	4	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	8	6	4
Middle East	OPT (baseline)	0	18	41	112	109	126	0	0	0	7	1	1	0	0	0	0	0	0	1	0	0	120	129	168
	OPT (low cost)	0	18	38	112	112	129	0	0	0	7	1	1	0	0	0	0	0	0	0	0	0	120	131	168
	OPT (low cost/pyrolysis)	0	9	16	112	114	144	0	0	0	7	1	1	0	0	0	0	0	0	0	0	0	120	124	162
	GRT (baseline)	0	31	32	111	98	74	0	0	0	7	1	1	0	0	0	0	0	0	0	0	0	118	130	107
N. America	OPT (baseline)	0	0	0	181	205	160	0	0	0	25	12	53	0	0	0	4	5	7	0	0	0	210	223	220
	OPT (low cost)	0	0	0	181	195	106	0	0	0	24	8	96	0	0	0	4	5	3	0	0	0	209	209	206
	OPT (low cost/pyrolysis)	0	0	0	182	294	240	0	0	0	25	4	56	0	0	0	4	6	7	0	0	0	211	304	304
	GRT (baseline)	0	0	0	139	154	144	0	0	0	14	0	0	0	0	0	4	3	10	0	0	0	157	157	153
Total	**OPT (baseline)**	0	43	60	526	551	509	0	0	0	41	19	60	0	0	0	4	5	7	1	0	0	**571**	**619**	**637**
	OPT (low cost)	0	43	58	527	546	430	0	0	0	39	16	103	0	0	0	4	5	3	1	0	0	**571**	**609**	**594**
	OPT (low cost/pyrolysis)	0	43	65	527	651	658	0	0	0	41	12	63	0	0	0	4	6	7	1	0	0	**572**	**712**	**794**
	GRT (baseline)	0	41	55	501	502	358	0	0	0	30	6	6	0	0	0	4	3	10	1	0	0	**534**	**551**	**428**