Ammonia to Power: Forecasting the Levelized Cost of Electricity from Green Ammonia in Large-scale Power Plants

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Abstract

Green ammonia, synthesized from air, water, and renewable energy, is a carbon-free energy storage vector with numerous potential energy applications, including dispatchable green electricity for the power sector. Due to the low cost of storing and transporting ammonia, green ammonia can be available as an energy source in all geographies, without the geological storage requirements of carbon capture and storage (CCS) or underground hydrogen storage. Here we contribute a novel techno-economic analysis to forecast the levelized cost of electricity (LCOE) from ammonia based on near-term and long-term technological developments to 2040, thus filling the knowledge gap for the application of ammonia as an energy vector in the electricity sector. We find that green ammonia could be available in many locations for less than 400 USD/t in 2040 with potential to be reduced to below 300 USD/t if electrolyzers achieve optimistic cost reductions, or when more favorable renewable resources are used to supply a global green ammonia market. We model ammonia-to-power via combustion in combined cycle gas turbines (CCGT) as a promising route to low-cost, dispatchable electricity generation. At power plant capacity factors below 25%, which may be increasingly common in electricity sectors with high variable renewable electricity, a tipping point occurs around 400 USD/t ammonia fuel price to enable green ammonia to compete with other prominent forms of dispatchable, low or zero-carbon technologies, such as gas, bio-energy, or coal fired power plants with post-combustion CCS.

Keywords: green ammonia, power generation, LCOE, ammonia cracking, gas turbine, Power-to-X

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1. Introduction

The electricity sector is responsible for nearly 40% of global carbon dioxide emissions today, with electricity demand predicted to grow by more than 50% by 2040 [1]. Forecasted electricity system models (ESM) predict a rapid uptake of variable renewable electricity (VRE) technologies, such as solar photovoltaics (PV) and wind, to decarbonize the electricity sector. Such scenarios have also identified the need for deploying balancing, dispatchable technology for reliable grid operation [1, 2, 3, 4]. Carbon capture, and storage (CCS), commonly associated with Bio-Energy and CCS (BECCS), is the most frequently cited methodology for dispatchable low-carbon electricity, with the International Energy Agency (IEA) forecasts including 5% of global electricity generation in 2040 from assets with CCS [1]. Beyond CCS, there is interest in hydrogen firing in gas turbines, albeit with cost challenges of hydrogen storage and transport [2, 5]. Meanwhile, green ammonia's role as a low-cost energy vector for the power sector has been overlooked in all forecasting and capacity planning models [1, 4].

Interest in green ammonia as an energy vector is gaining momentum with its inclusion as a key technology for cross-sector decarbonization in recent reports from several international organizations [5, 6, 7] as well as a focus of industry [8, 9]. Research is ongoing in improved green ammonia synthesis from VRE [10, 11] as well as use for energy purposes [12, 13].

Green ammonia is relevant to investigate for electricity generation because it is an energy-dense fuel with few technical barriers to adoption, and there will likely be a large global supply chain of green ammonia in the future. The recent momentum in decarbonization of the shipping industry using green ammonia [14, 15, 16] is an indicator of many of the advantages of ammonia that can be applied equally to large scale power generation, including scalability in production with declining costs, a relatively high energy density with simple storage requirements, safe use in industrial settings, and potential for being the lowest cost zero-carbon option. Forecasts for the role of ammonia as a shipping fuel range from 25% [17] to 99% [18] of global maritime fuel by 2050. Leading engine manufacturers are commencing with combustion development in their internal combustion engines (ICE) [9, 19]. Green methanol is another widely considered fuel for energy purposes such as shipping, but preliminary forecasts suggest green ammonia will be lower cost due to the high cost of direct air capture of CO_2 [5, 13].

The steps towards a global green ammonia supply chain are being driven by decarbonizing the large, already existing ammonia fertilizer supply chain [20], currently at 180 million tons per year [7], as well as the emerging energy uses, such as shipping [17] and hydrogen transport [21]. The shipping sector would require five times as much ammonia as the current global fertilizer industry by 2050 if it transitioned to 100% ammonia [18]. Production of industrial scale green ammonia is already being assessed for feasibility in Chile [22], New Zealand [23], Norway [20], Saudi Arabia [21], and four locations in Australia [24, 25, 26, 27] in anticipation of such large future markets. At such scales it is reasonable to assume that green ammonia would be available as an energy vector at most locations for electricity generation.

The levelized cost of ammonia (LCOA) is becoming more frequently modelled as green ammonia gains attention as an energy vector. Many models use general assumptions about the renewable electricity (RE) full load hours (FLH) and levelized cost of electricity (LCOE) to build a simple estimate of LCOA (e.g. 7,000 FLH at 18-21 USD/MWh for an LCOA of 225 USD/t NH_3 [15], 3,000 FLH at 25 USD/MWh for and LCOA of 350 USD/t NH_3 [5], and 8,000 FLH at 24 USD/MWh for an LCOA of 620 USD/t NH_3 [14]). However, these models are missing key plant components, such as substantial hydrogen storage and/or electricity storage needed to manage RE variability. There are several far more detailed models in the literature [28, 29, 30, 31] which demonstrate that to determine LCOA to a useful level of accuracy requires optimization to the process level based on the specific geographical wind and solar supply profile, local component costs, local financing costs, and synthesis plant flexibility, as found in [28]. These detailed models find LCOA for a specific site, rather than a broadly applicable LCOA forecast. In [28], this specificity is overcome by modelling LCOA at over 500 locations around the world. The results find that a range of 310 – 500 USD/t will be available in many locations around the world by 2030 [28]. However, this complex model and others are difficult to replicate, modify, and test for different input sensitivities. There is a knowledge gap in producing a geographically non-specific LCOA forecast for the market, such as in [5, 15], that approaches the complexity and accuracy of complex models, such as [28]. Thus, a novel model of LCOA forecasting is developed in this paper that is applicable to many geographic regions, using only solar PV with night-time battery storage integration, and validated with the complex model in [32]. This novel model is simpler than that presented in [28], and thus enables the addition of new technologies such as solar PV with single axis tracking and battery storage, including a transparent sensitivity analysis. Finally, the novel model presented here provides more detailed and practical plant design than the prevalent simple models, such as in [5].

Technological progress in ammonia-to-power has been extensively reviewed by [12], with notable progress in direct ammonia fuel cells for transport [13], co-firing with coal [33], and firing in gas turbines [34]. Analyses from [5] and [35] suggest that ammonia may be the lowest cost method of international trade of hydrogen, specifically to Japan, when compared with liquid organic hydrogen carriers and liquified hydrogen. However, there is a knowledge gap in the techno-economic comparison of green ammonia-to-power at power plant scale, especially compared with frontrunning low-carbon, dispatchable technologies such as fossil fuel with CCS, BECCS, and nuclear power. Moreover, the levelized cost of electricity (LCOE), the key indicator of economic competitiveness in the electricity sector, has not been calculated for near-term green ammonia-to-power technologies.

Therefore, the objectives of this paper are: (i) to forecast a widely available green ammonia LCOA from solar PV with highlighted sensitivities, (ii) to forecast a green ammonia-to-power levelized cost of electricity (LCOE) in the electricity sector, and (iii) to compare green ammonia to power at large scale with alternatives, including CCS and nuclear power to highlight scenarios where green ammonia may be competitive in the electricity sector in the future. The originality of this paper is in developing novel techno-economic models of power-to-ammonia via solar PV and batteries, and ammonia-to-power via combined cycle gas turbines (CCGT), based on near-term and long-term technological developments. Additionally, by pairing these models in one analysis, a more detailed understanding of the full ammonia energy system's key sensitivities is presented.

NOMENCLATURE	
ASU	**Air Separation Unit**
BECCS	**Bio-Energy with CCS**
BNEF	**Bloomberg New Energy Finance**
CAPEX	**Capital Expenditure**
CCGT	**Combined Cycle Gas Turbine**
CCS	**Carbon Capture and Storage**
DEA	**Danish Energy Agency**
ESM	**Electricity system model**
FLH	**Full Load Hours**
GHI	**Global Horizontal Irradiance**
H_2	**Hydrogen**
HB	**Haber-Bosch synthesis process**
ICE	**Internal Combustion Engines**
IEA	**International Energy Agency**
IRENA	**International Renewable Energy Agency**
LCOA	**Levelized cost of ammonia**
LCOE	**Levelized cost of electricity**
LHV	**Lower heating value**
LNG	**Liquefied Natural Gas**
N_2	**Nitrogen**
NH_3	**Ammonia**
O&M	**Operations and Maintenance**
PEM	**Proton Exchange Membrane**
PV	**Photovoltaic**
RE	**Renewable Electricity**
SMR	**Steam Methane Reforming**
TPD	**(Metric) Ton Per Day**
TRL	**Technology Readiness Level**
VRE	**Variable Renewable Energy**
WACC	**Weighted Average Cost of Capital**

2. Methodology

2.1 Green ammonia production costs

The LCOA has been calculated for 2020-2040 to determine the realistic fuel cost of green ammonia and to highlight key sensitivities. To forecast the LCOA, the production cost of green ammonia was modelled using an industrial scale green ammonia synthesis plant, using solar PV as the energy source (Fig. 1). Full cost and performance assumptions are listed in Appendix A, with forecasted reductions to 2040.

The LCOA was calculated using a simplified method based on the methodology of [32] for "islanded" production, i.e. with no connection to the electricity grid. Islanded production is seen as favorable for green ammonia projects due to the improved renewable electricity (RE) resources in locations far from the grid as well as avoided grid connection costs [36]. At the scale of average ammonia plants (500 – 1,500 metric ton per day (TPD)), hundreds of MW of RE resources are required, and thus onsite generation is preferred to grid connection.

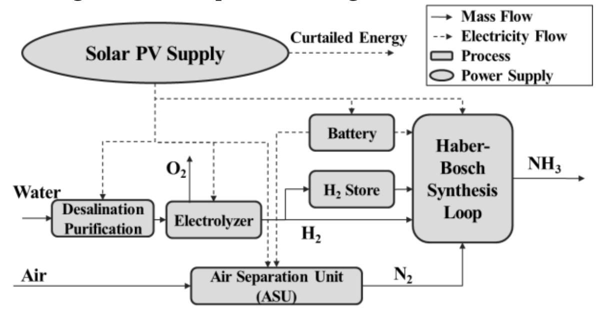

Fig. 1. Green ammonia synthesis process, based on [32]

In this model, techno-economic data is used for solar PV with single axis tracking. All equipment is sized using a binary daily profile (Fig. 2a), assuming that all of the required hydrogen is produced when solar electricity is available. Hydrogen is then stored in above ground hydrogen tanks at 200 bar to allow for a constant supply of hydrogen to the Haber-Bosch (HB) synthesis loop. The electricity requirement of the HB and air separation unit (ASU) is powered by battery storage when solar electricity is not available. This simplified approach has been validated with the model outlined in [32] when considering locations with only solar PV, with LCOA error of less than 10%, given the same input assumptions (Fig. 2b). Thus, this simplified methodology provides an approximate yet reliable LCOA estimate with visibility to key sensitivities. A generic solar global horizontal irradiance (GHI) of 2,000 kWh/m^2/year is used in this analysis. This level of solar irradiation was chosen because it is widely available, including in parts the USA and Central America, South America, India, China, northern Africa, southern Africa, the Middle East, Australia, and southern Europe [37]. Single axis tracking solar PV systems are becoming increasingly common, accounting for nearly 70% of utility scale solar PV installations in the US in 2018 [38]. Using the assumptions listed in Appendix A, the achieved LCOE from single axis tracking solar PV is reduced from 28.5 USD/MWh in 2020 to 16.8 USD/MWh in 2040. Wind and wind/solar hybrid plants were not considered in this analysis, as they would require more complex LCOA methodology as in [32]. Additionally, solar PV has a lower long-term LCOE forecast [1].

The key challenge in green ammonia plant design is the limited flexibility of the HB synthesis loop, which is unable to mirror the incoming VRE profile [32]. In a first instance, hydrogen storage can mitigate the HB flexibility requirements. However, new HB technology will likely have increased flexibility to reduce the need for hydrogen storage, and thus reduce costs [28]. Some methods for reducing the minimum

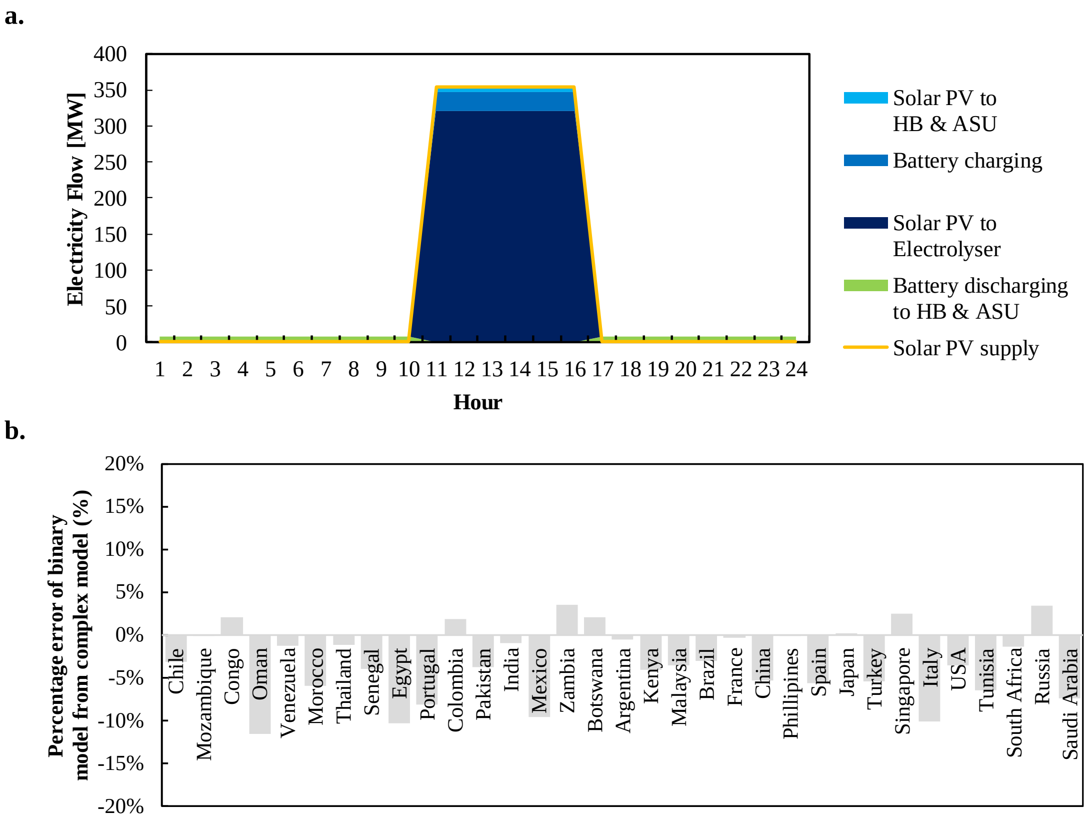

Fig. 2. a. Power allocation for 10 t NH$_3$/hr green ammonia synthesis plant using simplified, binary methodology for plant equipment sizing**. b.** LCOA percentage error between simplified LCOA methodology and methodology used in [32] at 33 locations using solar PV with single axis tracking.

load of the HB to 10-20% or rated capacity include reducing the purge rate and increasing the fraction of inert gases in the reactor [39]. Other computational research suggests a minimum of 33% of nameplate capacity can be achieved by varying both the inert gas fraction and the H_2/N_2 ratio [11]. In this analysis, the assumption of two days of hydrogen storage in 2020 was reduced to one day of hydrogen storage in 2040, which is achievable based on modelling of plants with high HB flexibility of 20% minimum load [29].

LCOA was calculated using Eqn 1. [28]

$$\text{LCOA} = \frac{\sum_{t=0}^{n} \frac{C_t + O\&M_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{A_t}{(1+r)^t}} \qquad \text{(Eqn 1)}$$

Where

C_t = Investment expenditures in year t
A_t = Ammonia produced in year t
$O\&M_t$ = Operations and maintenance expenditures in the year t
n = economic lifetime of the plant
r = Weighted average cost of capital (WACC)

2.2 Ammonia to power costs

Ammonia and the hydrogen contained within ammonia can be transformed into electricity via thermochemical routes (turbines or engines) or electrochemical routes (fuel cells). Additionally, ammonia can be decomposed or "cracked" back into H_2 and N_2 via thermal decomposition in the presence of a catalyst (Eqn 2) to feed hydrogen compatible power generation equipment, such as hydrogen fuel cells.

$$2NH_3 \rightarrow 3H_2 + N_2 \quad \Delta H = 92\ kJ/mol \qquad \text{(Eqn 2)}$$

An ammonia-to-power combined cycle gas turbine (CCGT) system was selected for lowest possible LCOE at power plant scale (100's of MW) based on cost and high technology readiness level (TRL) technology. Other technologies considered included fuel cells and co-firing with coal. While the technology for direct ammonia fuel cells is being researched [13] and demonstrated [40] at small scale for transport sector applications, the costs projections are unknown and likely cannot compete for some time with gas turbines at such large scales. Capital cost is the most important factor to consider because the efficiency gains of fuel cells are of little advantage when comparing with 60% efficient CCGT systems. The economic advantage of any efficiency gain is minimal due to the low annual fuel consumption of a plant at the low utilization rates projected, whereas the capital cost disadvantage is significant at low utilization. Similarly, ammonia cracking paired with hydrogen fuel cells was excluded from this analysis because of high capital cost of PEM fuel cells and high footprint of alkaline fuel cells at 100's of MW scale [41], and thus high cost. Finally, ammonia powered CCGT has lower projected costs than co-firing ammonia with coal for steam turbine power generation due to the high emissions of coal co-firing [42].

2.2.1 Ammonia CCGT System Overview

Ammonia-fueled CCGT systems can combust hydrogen derived from ammonia [43], or a blend of ammonia and hydrogen [34], or ammonia directly. This paper's analysis predicts that combustion technologies will progress over time from pure hydrogen (Phase 1), to blends of hydrogen and ammonia (Phase 2), to pure ammonia (Phase 3), in line with current industry research and development, and progress towards lower LCOE.

Phase 1: In industry, most CCGT manufacturers have committed to a 100% H_2 firing capability by 2030 [46]. Small scale 100% firing has been announced by Siemens for 12 MW by 2023 [47] and the first commercial project has been announced by Mitsubishi Hitachi Power Systems for 840 MW of hydrogen compatible gas turbines operating at 30% H_2 in 2025 and 100% H_2 by 2045 [48]. To address the difficulty of storing GWh of hydrogen, the Mitsubishi project will utilize a very large underground salt cavern for hydrogen storage, which is conveniently available near the site in Utah, USA [48]. Some technical challenges with hydrogen compatibility include auto-ignition flashback, thermoacoustic effects, higher flame temperature and resulting NO_x emissions, and challenges in designing for full flexibility from 100% natural gas to 100% hydrogen in one turbine (e.g. hydrogen requires significantly larger pipe sizes to handle the increased flow rate of volume to the turbine to deliver the same power) [49]. This last point is particularly challenging if turbines are connected to the natural gas transmission grid, and thus need to accommodate a fuel mix that may change several times over the coming decades.

Phase 2: Recent research into ammonia combustion has focused on exploring fuel blends to provide greater combustion stability, as well as emissions control of NO_x and unburned NH_3 than pure ammonia combustion [34]. In particular, 70% NH_3 /30% H_2 by volume has shown the best stability and performance in gas turbine research [34]. As early evidence of this technology, the world's first demonstrator of the full power-to-ammonia-to-power cycle at Rutherford Appleton Laboratory in Oxfordshire, UK uses a blend of 70% NH_3 /30% H_2 by volume to achieve stability in a reciprocating engine designed for combustion on natural gas [8]. Furthermore, steam injection techniques show early promise for controlling NO_x emissions in these blends without sacrificing fuel efficiency [50].

While the exact ratio may be subject to further research and development, dual-fueled engines are a promising route for easier engine re-design, as demonstrated in ICE engine development in the shipping industry which is using dual-fueled ammonia engines to enable near-term implementation [9].

Other blend research includes ammonia / methane blends [51], which may enable a variation of Phase 2 to be adopted in parallel with Phase 1, albeit with some carbon emissions.

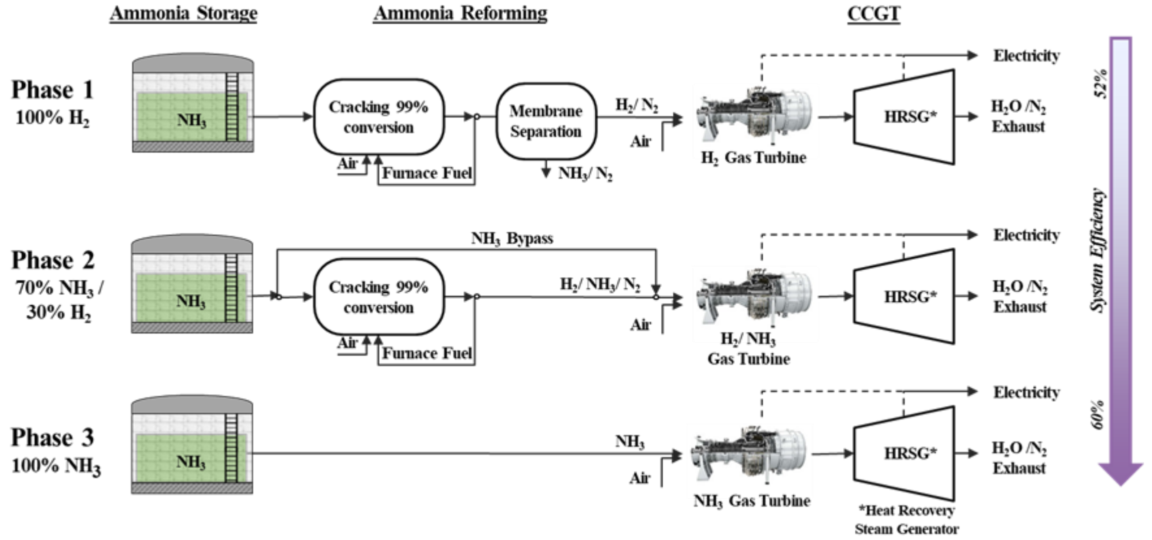

Fig. 3. AMMONIA-TO-POWER: Ammonia fuelled CCGT configurations as modelled in three cases of 100% H_2, 70% NH_3 / 30% H_2, and 100% NH_3. Additional model details provided in Appendix B.

Phase 3: Finally, Phase 3 technology will utilize ammonia directly. Pure ammonia has several challenging properties related to combustion, including high auto-ignition temperature and low flame speed [12]. This technology is still in the research stage, with a small scale 50 kW micro gas turbine recently demonstrated on 100% NH_3 in Japan [45], with further research into pure combustion techniques ongoing, such as recent work in cyclonic burners [52].

2.2.2 Ammonia Cracker Costs

Forecasting the LCOE of Phase 1 and 2 requires a techno-economic analysis of an integrated ammonia decomposition system with CCGT.

The heat required for the high temperature thermocatalytic reforming in the system can be generated by cannibalizing a fraction of the decomposed product stream and burning this hydrogen rich stream in a fired reformer. This approach is similar to the one reported in [44] and is depicted in Phase 1 of Fig. 3. In a fully heat-integrated process, liquid NH_3 would be vaporized and preheated using the low-grade heat of the exhaust stream. The integrated system in Phases 1 and 2 were modelled in ASPEN Plus to determine the heat integration, required rate of cannibalization, and overall system ammonia-to-power efficiency (Appendix B). The system CCGT was based on Siemens SGT-800, a medium (62.5 MW) turbine already capable of running on 50% H_2 [53]. In the modelled reformer, 99% conversion was assumed at 850°C. This conversion and temperature assumption was based on small-scale commercial ammonia decomposition reactors, which use nickel catalysts at 850 °C [54, 55]. Literature suggests high conversion cracking is achievable between 650 °C and 900 °C depending on the catalyst [56]; however, for low cost and high technological maturity, nickel catalyst has been found to be the most cost-effective catalyst [57].

The technology for ammonia cracking is commercially available at small scale (i.e. less than 100 kg H_2/hr output) [58, 54, 55]. Large scale cracking can be modelled using steam methane reforming (SMR) as a basis, due to the analogous thermocatalytic cracking reactor design employed. Large-scale, thermocatalytic reformers for SMR are large fireboxes with dimensions at the scale of a building [59], with substantial economies of scale (Fig. 4). In a large scale cracker, ammonia would be fed through parallel, vertical, catalyst filled tubes, which are arranged in the firebox [60]. The design would closely resemble SMR because both processes are constrained by maintaining high enough reaction temperature inside the tubes against the endothermic cracking reaction (ΔH = 31 kJ/mol H_2 in NH_3 decomposition versus a slightly higher SMR ΔH = 41-69 kJ/mol H_2). This design constraint is managed through the design of the tube diameter and firebox temperature.

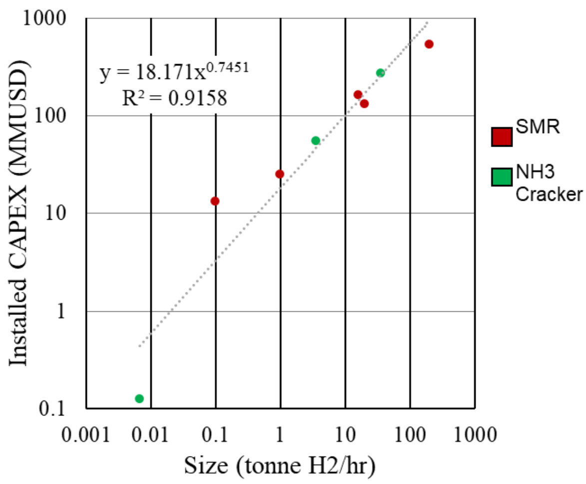

Fig. 4. CRACKER COST CURVE: Ammonia Reformer Installed CAPEX cost curve based on literature values for ammonia crackers at 0.007 [61], 3.6 and 36 ton H_2/hr [43] and SMR at 0.10, 1.0, 20, 200 ton H_2/hr [62], and SMR at 15.8 ton H_2/hr [63].

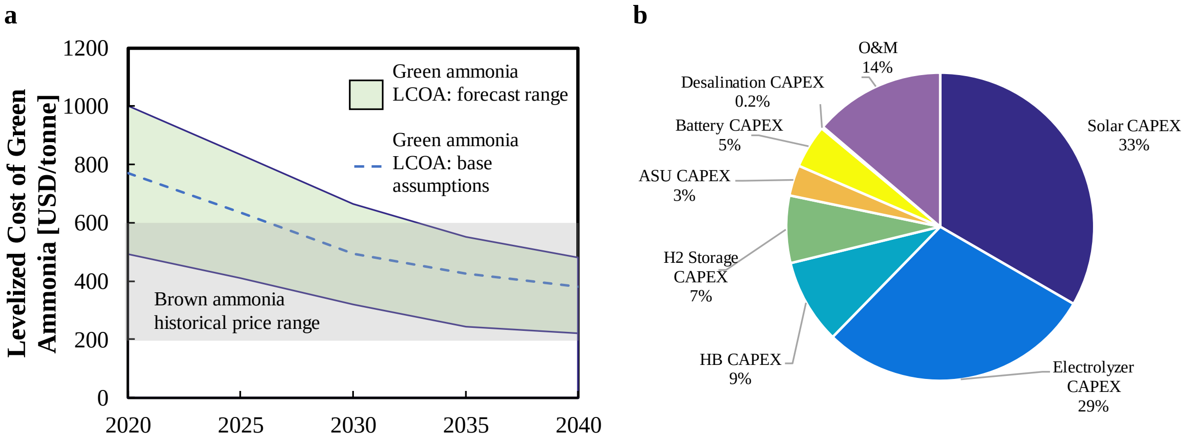

Fig. 5 . POWER-TO-AMMONIA: a. Green ammonia production cost forecasted 2020 to 2040 with historical fossil fuel based ammonia price range of 200 – 600 USD/t **[86]**. LCOA range calculated using low and high literature estimates for electrolyzer CAPEX, WACC, and solar PV LCOE, as presented in Table 1. **b.** LCOA cost breakdown for 2040, base assumptions (Appendix A).

In Phase 1, the cannibalization stream was calculated to be 20.5% of the product stream using an ASPEN model of the system (Appendix B). Due to this fuel cannibalization in the pre-treatment cracking stage, overall fuel efficiency (based on the LHV of ammonia) was thus reduced to 52.5% from the base 60% CCGT efficiency [53]. Phase 2 has a fuel efficiency of 57.4%, using a scaled model of Phase 1, with most of the ammonia bypassing the efficiency losses in the cracking stage. For Phase 3, the baseline CCGT fuel efficiency is expected to be around 60%..

The ammonia reformer was the only additional CAPEX considered for an ammonia CCGT system compared to a natural gas CCGT system. Costs for ammonia storage tanks were disregarded in this analysis because they were assumed to be the same cost as LNG. Due to the overlapping properties, some storage tanks for LNG can even be used for the storage of ammonia [64]. Therefore, the estimated increase in CCGT installed CAPEX for ammonia was based solely on the addition of an ammonia reformer.

2.3 LCOE Methodology

The LCOE can be broken down into component costs for fuel, installed CAPEX, operations and maintenance (O&M), and emissions. Techno-economic data for supercritical pulverized coal power plants with CCS, natural gas CCGT with CCS, nuclear, bio-energy with CCS (BECCS), and the three phases of ammonia CCGT shown in Fig. 3 are summarized in Appendix C. The LCOE for each Phase was calculated using Eqn 3. [65]

$$\mathrm{LCOE} = \frac{\sum_{t=0}^{n} \frac{C_t + O\&M_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}} \qquad \text{(Eqn 3)}$$

Where

C_t = Investment expenditures in year t
E_t = Electricity produced in year t
$O\&M_t$ = Operations and maintenance expenditures in year t
n = economic lifetime of the plant
r = Weighted average cost of capital (WACC)

3 Results and Discussion

3.1 Ammonia fuel price

Green ammonia LCOA modelled from solar PV based on assumptions listed in Appendix A will reach 380 USD/t NH_3 by 2040 (Fig. 5a). The key cost components are the electrolyzer CAPEX and the solar PV CAPEX. The key sensitivities assessed for LCOA were the electrolyzer CAPEX, the weighted average cost of capital (WACC) to finance the investment, the RE LCOE, and the RE full load hours (FLH), as shown in Fig. 6. Table 1 highlights low and high estimates for each key sensitivity in 2040, as found in the literature, and the combined effect of electrolyzer CAPEX, WACC, and solar PV LCOE on the LCOA. The uncertainty in these three variables is used to calculate the range depicted in Fig. 5a. The LCOA is more sensitive to the lower literature estimates, especially for the electrolyzer CAPEX and the RE full load hours.

3.1.1 Sensitivity: Electrolyzer CAPEX

The CAPEX for electrolyzers is very uncertain; however, this uncertainty will likely be resolved in the coming years as more projects are commissioned, and a clear experience curve is derived for the technology. Electrolyzer experience curves are likely the most accurate method for forecasting costs, based on those developed for other RE technologies such as wind and solar PV, which follow very reliable cost reduction rates based on installed capacity, i.e. learning rates [66, 67]. However, PEM electrolyzers do not have enough data and alkaline electrolyzers do not show a reliable learning rate when looking at historical data [68]. For alkaline electrolyzers, it is difficult to accurately calculate a learning rate at this point due to i) a wide CAPEX spread in the available data, ii) a lack of clarity in the data as to which components are included in CAPEX (e.g. compressors, gas rectifiers, storage tanks, balance of plant, engineering, etc.), and iii) confounding effects of project scale downsizing from large systems since 1990 due to the introduction of SMR for large scale hydrogen users [68].

Table 1: LCOA Sensitivity assumptions

	2020	2025	2030	2035	2040	Unit	Reference
Electrolyzer CAPEX							
Lower literature estimate	400	264	115	106	98	USD/kW	Bloomberg NEF [78]
Base estimate	770	655	540	488	435	USD/kW	IRENA 2020 Global Renewables Outlook [93]
Higher literature estimate	939	834	730	600	511	USD/kW	Upper estimate from IEA [5] & DEA [81]
Weighted Average Cost of Capital (WACC)							
Lower literature estimate	4%	4%	4%	4%	4%	%	Offshore wind in Europe has achieved 4% in 2018 [1]
Base estimate	7.5%	7.5%	7.5%	7.5%	7.5%	%	Standard used in IRENA analyses for OECD and China [82]
Higher literature estimate	10%	10%	10%	10%	10%	%	Developing country assumption in IRENA analyses [82]
Solar PV LCOE (widely achievable)							
Lower literature estimate	24	22	20	15	14	USD/MWh	IRENA Solar PV low of 20 USD/MWh in 2030 and 14 USD/MWh in 2050 [91]. Curve generated to scale from base assumptions (see Appendix A).
Base estimate	29	24	19	18	17	USD/MWh	See Appendix A. Calculated from component costs and widely achievable solar irradiation.
Higher literature estimate	34	28	23	21	20	USD/MWh	Assuming IRENA Solar PV low forecast for 2030 [91] is not achieved until 2050. Curve generated to scale from base assumptions (see Appendix A).
LCOA from Solar PV							
Lower estimate	**493**	**412**	**321**	**244**	**222**	**USD/t NH3**	See Appendix A for further methodology
Base estimate	**771**	**634**	**494**	**426**	**380**	**USD/t NH3**	See Appendix A for further methodology
Higher estimate	**1000**	**834**	**664**	**550**	**480**	**USD/t NH3**	See Appendix A for further methodology
Renewable Full Load Hours*							
Lower literature estimate	1,500	1,500	1,500	1,500	1,500	hr/yr	IEA average capacity factor of 23% for USA PV in 2040 [1]
Base estimate	2,000	2,000	2,000	2,000	2,000	hr/yr	See Appendix A.
Higher literature estimate	5,600	5,600	5,600	5,600	5,600	hr/yr	64% wind/solar combined capacity factor available in Patagonia [29]

**RE FLH sensitivity not used to calculate LCOA range in Fig. 5a due to overlapping effects with solar PV LCOE. Single variable sensitivity presented in Fig. 6*

While the historical experience curve is difficult to determine, the future curve should be clear in the coming years. Electrolyzers have huge predicted growth, with IRENA predicting 1,700 GW world capacity by 2050 [2], which requires 33% annual installation growth from the current installed capacity of 253 MW in 2019 [69]. Already, the current pipeline of electrolyzer projects for completion in the mid-2020s is over 8 GW [70].

3.1.2 Sensitivity: Renewable Full Load Hours

The other notable sensitivity for the LCOE calculations is the RE FLH, which could be increased significantly in regions with more favorable solar PV and wind resources. For example, the average FLH for offshore wind in Europe is projected to be over 5,100 hours in 2040 [1]. Hybrid wind and solar PV plants may be the most cost effective methods of achieving higher FLH, with analysis of green ammonia plant design in Chile and Argentina modelling over 5,600 combined FLH [29]. However, increasing RE FLH may also increase the RE LCOE, in the example of wind, or increase the transport costs, in the example of producing ammonia in favorable regions, such as Chile, and exporting it to regions with less favorable RE resources. Additionally, these high FLH locations may be prioritized for other purposes, such as synthetic fuel production for aviation.

The average of all the lowest sensitivity estimates and all the highest sensitivity values is 294 USD/t and 450 USD/t, respectively. Importantly, the effects of the sensitivities are non-additive. For example, high RE FLH has a very favorable effect on LCOA but would have almost a 50% smaller effect if the electrolyzer CAPEX was at the lowest literature value of 98 USD/kW.

Interestingly, an LCOA below 200 USD/t can be achieved at an electrolyzer CAPEX of 98 USD/kW and WACC of 4%. This would likely be a game-changing LCOA for many sectors, including the power sector. This sensitivity analysis highlights the potential for green ammonia to be an extremely cheap fuel in the long term, given the right techno-economic developments.

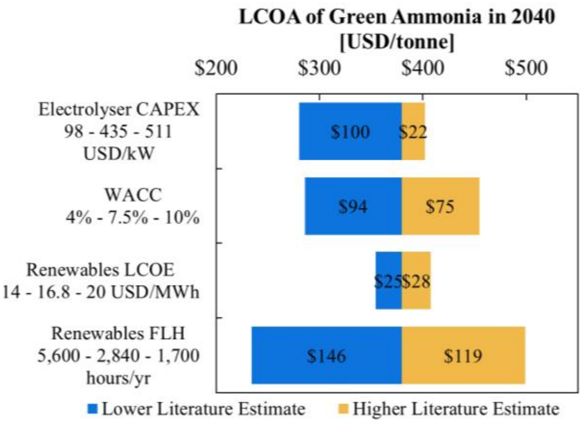

Fig. 6. Sensitivity analysis of LCOA in 2040 based on low and high values from literature for key model inputs. See Table 1.

3.2 Green ammonia levelized cost of electricity (LCOE)

The resulting average LCOE for each of the Phases for green ammonia-to-electricity are shown in Fig. 7**Error! Reference source not found.**a. Compared to other prominent low-carbon options, green ammonia is most competitive at low power plant capacity factors, specifically below 25% (Fig. 7b). While capacity factors above 50% are common today for dispatchable electricity generation [1], projections into the future suggest much lower capacity factors. For example, the IEA identified capacity factors as low as 15% for peaking gas turbines in future energy systems [5] and BNEF identified 25% as an approximate capacity factor required for dispatchable generation in scenarios compatible with 2°C decarbonization [4].

Based on the assumptions listed in Appendix C, ammonia direct firing in CCGT (i.e. Phase 3 technology) has an LCOE of 167 USD/MWh at a 25% power plant capacity factor, with the only lower LCOE generated in gas CCGT with CCS using future cost assumptions (30% reduced in CAPEX and OPEX from 2020 to 2040 [71]).

The key sensitivities considered for green ammonia's LCOE are the fuel price, the WACC, the power plant capacity factor, and the NH_3 firing compatibility (i.e. Phase 1, 2, or 3 ammonia CCGT technology). Table 2 highlights low and high estimates for each component in 2040, as found in literature, and Fig. 8 shows the LCOE sensitivity. The LCOE is most sensitive to the fuel price estimates and power plant capacity factor. Green ammonia fuel price, i.e. LCOA, is subject to wide uncertainty, with more potential on the lower end, as shown in Fig. 6.

Fig. 7 and Fig. 8 also highlight the cost difference in the three phases of ammonia CCGT technology (i.e. NH_3 compatibility). Phases 2 and 3 have 10% and 15% lower LCOE than Phase 1, respectively. These results highlight the value for CCGT manufacturers to pursue pure ammonia combustion.

3.2.1 Comparing ammonia CCGT with CCS

CCS is the dominant low-carbon, dispatchable technology used in energy systems models, with over 400 GW of fossil fuel with CCS deployed by 2050 in the latest IEA forecasts [1]. However, the results of this analysis suggest that green ammonia firing in CCGT may achieve lower costs by 2040, or at least will be very competitive, and therefore should be included in prominent models.

In addition to fossil fuel combustion with CCS, bioenergy with CCS (BECCS) is a widely discussed concept for employing net negative CO_2 emissions. The results suggest that ammonia to power is over 20% lower cost at low plant capacity factors. Furthermore, there is uncertainty in the negative emissions provided based on land-use change, fuel transport costs, and the energy required to grow biomass [72, 73]. There are also uncertainties in the biomass available for BECCS [73] as well as other sectors looking to use biogenic sources, such as aviation fuel.

Green ammonia enjoys several important advantages over CCS-based alternatives beyond LCOE. Firstly, green ammonia is geographically independent with low transport costs and high likelihood to be available in all ports if it becomes widely used in the shipping sector. CCS requires nearby underground storage or expensive CO_2 transport to suitable underground storage locations. Secondly, ammonia CCGT can easily scale down to tens of MW, providing useful balancing services to a more decentralized grid of the future. Both nuclear and CCS, on the other hand, are often considered at only GW scales [1]. Thirdly, upfront capital costs for ammonia CCGT are substantially lower. Ammonia CCGT electricity production is dominated by fuel costs, while CCS-based electricity is dominated by CAPEX (Fig. 7a). Per kW installed, ammonia CCGT adds 402 USD/kW in Phase 1, while CCS adds 1,116 USD/kW for gas CCGT and 1,426 USD/kW for supercritical coal (Appendix C). The first commercial CCS projects are forecasted to cost around 1 billion USD and take more than five years to design and build [1]. The smaller scale potential of ammonia CCGT favors more projects, sooner, and thus higher potential for cost reductions from experience curves [67]. Finally, CCS technologies are at best 90-95% effective at capturing emissions [74], while ammonia CCGT is fundamentally carbon-free (although other greenhouse gas emissions, such as NO_x, will need to be controlled).

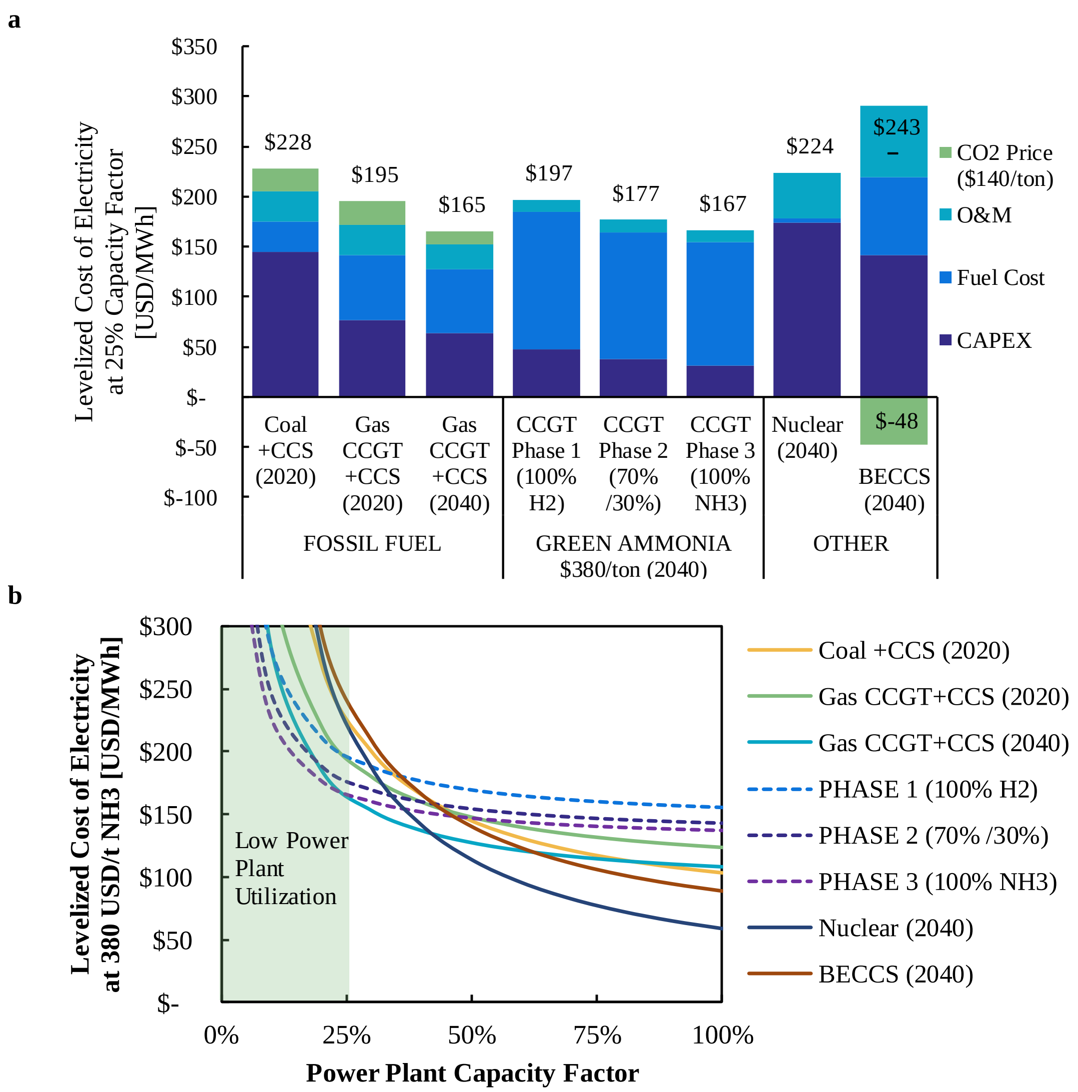

Fig. 7. a. LCOE comparison of low/no carbon dispatchable electricity using EU electricity sector assumptions at 25% power plant capacity factor based on BNEF forecasts in high VRE penetration scenarios [4]. **b.** LCOE of low/no carbon dispatchable electricity at a range of power plant capacity factors.

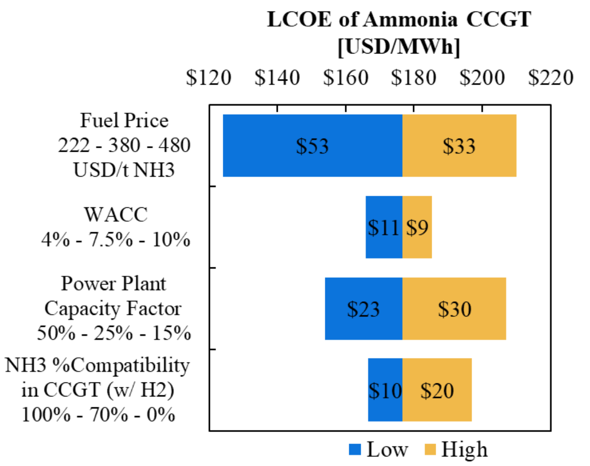

Fig. 8. Sensitivity analysis of LCOE in 2040 based on low and high values for key model inputs

4. Conclusions

Green ammonia is a technically viable and economically competitive fuel for decarbonization of the electricity sector via high efficiency gas turbine power plants by 2040. The levelized cost of electricity from green ammonia is forecasted to be 167 - 197 USD/MWh at 25% power plant capacity factor in 2040, assuming a widely available green ammonia fuel price of 380 USD/t. This cost of electricity is comparable with natural gas power plants with post-combustion CCS and is significantly lower than coal with CCS, bio-energy with CCS, and nuclear power. The additional costs of 30 USD/MWh associated with cracking ammonia to fuel hydrogen fired gas turbines suggests that gas turbine manufacturers should prioritize achieving a more ammonia compatible turbine technology in the long term.

Currently, there are large uncertainties in the production cost of green ammonia, primarily due to a wide range of forecasts and lack of reliable experience curve data for electrolyzer capital cost. This uncertainty should be reduced substantially in the coming years as more large scale electrolyzer projects are deployed. A similar sized uncertainty is present in the cost of capital, which may depend on economic and political factors. Our estimates for the levelized cost forecast of green ammonia in 2040 ranges from 222 USD/t to 480 USD/t due to a range of assumptions on electrolyzer costs, cost of capital, and widely achievable solar PV costs.

While the levelized cost of electricity is a useful indicator of economic competitiveness, it is only when it is integrated into a national grid that the true economic competitiveness of green ammonia can be understood. In particular, specific grids require different capacity utilization rates of dispatchable energy sources [3] and have different available fuel prices, including between domestic and imported green ammonia. Further research will be required to understand the implications of such considerations at a grid/regional scale. Additional regional-specific considerations that might need to be addressed include whether a mismatch exists between low cost renewable supply and electricity demand (such as in Japan [5]), seasonality of renewable supply, the price of competing technologies (such as the low price of gas in the USA which favors CCS technologies [1] or hydrogen salt cavern potential in the UK [75]), the need for flexibility (as CCGT offers less flexibility than open cycle GT [76]), and, finally, policy decisions towards decarbonization and supporting different technological trajectories.

With growing interest in the use of green ammonia for decarbonizing fertilizer production [20] and shipping [14], experience with this energy vector will only increase. Given the consistent and predictable trends shown in other new clean technologies [67], such experience is likely to bring consistent cost reductions. Given the additional advantages that green ammonia-to-electricity production enjoys over other currently favored alternatives, such as nuclear and CCS, particularly in future VRE dominated grids with declining dispatchable capacity factor requirements, it clearly warrants serious attention as a clean fuel of the future.

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Table 2: LCOE Sensitivity limits

	2040 Forecast	Unit	Reference
Fuel Price			
Lower literature estimate	222	USD/t NH_3	Based on lower estimates in electrolyzer CAPEX, WACC, and solar PV LCOE (Table 1, Fig. 5a)
Base estimate	3890	USD/t NH_3	Base estimates, as shown in Fig. 5a and Appendix A
Higher literature estimate	480	USD/t NH_3	Based on higher estimates in electrolyzer CAPEX, WACC, and solar PV LCOE (Table 1, Fig. 5a)
Weighted Average Cost of Capital (WACC)			
Lower literature estimate	4%	%	Offshore wind in Europe has achieved 4% in 2018 [1]
Base estimate	7.5%	%	Standard used in IRENA analyses for OECD and China [82]
Higher literature estimate	10%	%	Developing country assumption in IRENA analyses [82]
Power Plant Capacity Factor			
Lower literature estimate	15%	%	Lower capacity factor used by [5] for H2 peaking gas turbines in future energy systems
Base estimate	25%	%	Identified as approximate capacity factor for technology required for 2C decarbonization in [4]
Higher literature estimate	50%	%	Gas CCGT capacity factor forecasted for USA, China, and India in [1] in 2040
NH_3 %Compatibility in CCGT (w/ H_2)			
Lower literature estimate	0%	%NH_3 by volume	Phase 1 (See section 2.2)
Base estimate	70%	%NH_3 by volume	Phase 2 (See section 2.2)
Higher literature estimate	100%	%NH_3 by volume	Phase 3 (See section 2.2)

Appendix A: Power-to-ammonia model and cost assumptions

Table A1: Techno-economic assumptions for green ammonia production (base case)

Component Technical / Economic Assumption	2020	2025	Year 2030	2035	2040	Unit Note: 2019USD	Reference
Solar PV (single axis tracking)							
Solar installed CAPEX	576	493	410	386	363	$USD/MW_{p,DC}$	DEA [41]
Global Horizontal Irradiance (GHI)	2,000	2,000	2,000	2,000	2,000	$kWh/m^2/yr$	Global Solar Atlas [37]
Performance ratio (measure of combined losses)	0.86	0.91	0.95	0.96	0.96		DEA [41]
Capacity Factor (fixed tilt, DC rating)	20%	21%	22%	22%	22%	%	Calculated
DC/AC Sizing Factor (also called Inverter Loading Ratio)	1.25	1.25	1.25	1.25	1.25	W_{DC}/W_{AC}	DEA [41] and high insolation regions (>1,890 GHI) with single axis tracking average 1.28 [38]
Capacity Factor (fixed tilt, AC rating)	25%	26%	27%	27%	27%	%	Calculated. Agrees with high insolation regions in USA [38]
Single axis tracking increase to capacity factor	5%	5%	5%	5%	5%	%	High insolation regions show up to 5% point increase to capacity factor due to single axis tracking [38]
Capacity Factor (single axis tracking, AC rating)	30%	31%	32%	32%	32%	%	Calculated, and agrees with 2018 average of 30.4% with range up to 34% in high insolation regions in USA [38]
Solar single axis tracking average annual full load hours (AC rating)	2,588	2,701	2,813	2,826	2,838	$kWh/yr/kW_{AC}$	Calculated
O&M	7,400	6,800	6,200	5,950	5,700	$USD/MW_{p,DC}/yr$	DEA [41]
LCOE	28.5	23.6	19.1	18.0	16.8	USD/MWh	Calculated
Electrolyzer							
Electrolyzer CAPEX	770	655	540	488	435	USD/kW input	IRENA 2020 Global Renewables Outlook [93]
Efficiency [LHV of H2]	64%	67%	69%	72%	74%	%	IEA [5]
O&M	1.5%	1.5%	1.5%	1.5%	1.5%	% of CAPEX	IEA [5]
Stack Lifetime (operating hours)	95,000	95,000	95,000	100,000	100,000	hr	IEA [5]
Ammonia Synthesis							
Haber-Bosch CAPEX	3,300	3,300	3,300	3,300	3,300	USD/kg NH3/hr	[77]
Air Separation Unit (ASU) CAPEX	1,450	1,450	1,450	1,450	1,450	USD/kg N2/hr	[77]
Haber-Bosch electricity consumption	0.6	0.6	0.6	0.6	0.6	MWh/t NH3	[32]
ASU electricity consumption	0.119	0.119	0.119	0.119	0.119	MWh/t N2	[32]
H_2 Storage required for HB Management	2.0	2.0	1.5	1.0	1.0	days at full load	Modified from [29]
Hydrogen Storage							
Aboveground (200 bar w/o compressors) CAPEX	1,050	961	872	743	615	USD/kg	DEA [80]
Lithium Ion Battery							
CAPEX (Energy Component)	271	218	166	138	110	USD/kWh	DEA [80]
CAPEX (Power Component)	315	251	187	152	117	USD/kW	DEA [80]
Fixed O&M	631	631	631	631	631	USD/MW/yr	DEA [80]
Variable O&M	2.3	2.2	2.1	2.0	2.0	USD/MWh	DEA [80]
Desalination							
Installed CAPEX	5.72	5.72	5.72	5.72	5.72	$USD/m^3/yr$	[87] assuming mechanical vapor compression from [30]
Financing							
Weighted Average Cost of Capital (WACC)	7.5%	7.5%	7.5%	7.5%	7.5%	%	IRENA [82]

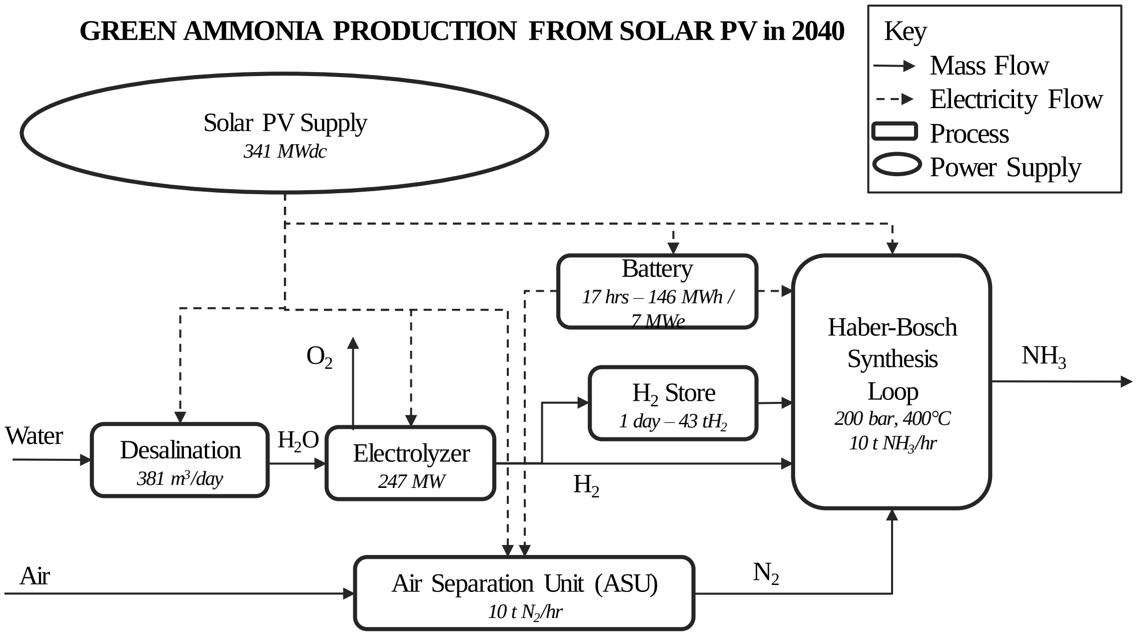

Figure A1: Diagram for solar PV, islanded green ammonia production plant in 2040

Table A2: Results of solar power to ammonia plant design for base case assumptions

	Year				
	2020	2025	2030	2035	2040
Plant Sizing					
NH_3 Production [t/hr]	10	10	10	10	10
Battery storage [hr]	17	17	16	16	16
H_2 storage (t)	85	85	64	43	43
Battery Storage (MWh)	152	149	146	146	146
Battery capacity (MWe)	7	7	7	7	7
H_2 Produced (t /yr)	15,558	15,558	15,558	15,558	15,558
Electrolyser Size (MW)	313	289	267	257	247
RE Size (MWdc)	427	395	367	353	341
RE Size (MWac)	342	316	293	283	273
Water desalination size (m3/day)	381	381	381	381	381
Plant Costs					
Electrolyser CAPEX (MUSD)	241	189	144	125	107
HB CAPEX (MUSD)	33	33	33	33	33
H_2 Storage CAPEX (MUSD)	90	82	56	32	26
ASU CAPEX (MUSD)	12	12	12	12	12
Battery CAPEX (MUSD)	43	34	26	21	17
Desalination CAPEX (MUSD)	1	1	1	1	1
Annual O&M (MUSD)	9	7	6	5	5
Solar CAPEX (MUSD)	246	195	150	137	124
Solar O&M (MUSD)	3	3	2	2	2
Contribution to LCOA					
Solar CAPEX (USD)	252	200	154	140	127
Electrolyzer CAPEX (USD)	247	194	148	128	110
HB CAPEX (USD)	34	34	34	34	34
H_2 Storage CAPEX (USD)	92	84	57	32	27
ASU CAPEX (USD)	12	12	12	12	12
Battery CAPEX (USD)	44	35	26	22	17
Desalination CAPEX (USD)	0.8	0.8	0.8	0.8	0.8
O&M (USD)	89	75	62	57	52
Total LCOA (USD)	**771**	**634**	**494**	**426**	**380**

Appendix B: Ammonia-to-power model

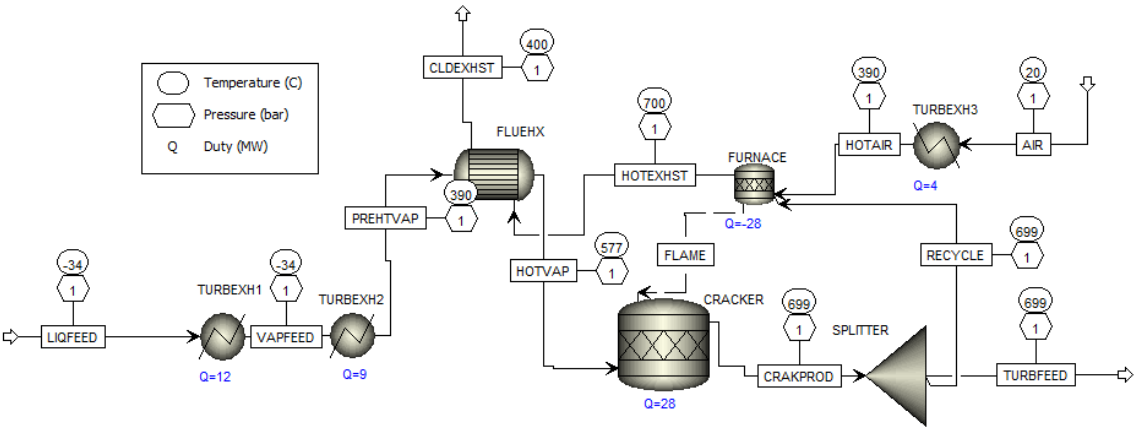

Fig B1. ASPEN Plus v9 model of ammonia decomposition reactor

Table B1: ASPEN Plus v9 modelling assumptions and results

Key user defined variables		Unit	Reference
TURBFEED Flow Rate	4.4	tH_2/hr	Calculated based on Siemens SGT800 82 MW CCGT 1 x 1 configuration, 60% fuel efficiency, assuming same fuel efficiency for H_2 as natural gas [92]
CRACKER reactor conversion	99%	%	Based on cracking achieved in small-scale commercial ammonia decomposition reactors [54, 55].
CRACKER outlet temperature	700	C	Literature suggests high conversion cracking is achievable between 650 °C and 900 °C depending on the catalyst [56]
LIQFEED temperature	-34	C	
Excess air ratio	1.12		
Process Units			
TURBEXH1, TURBEXH2, TURBEXH3	Heat exchangers modelled as heaters. Assuming heat from turbine exhaust is 400 C and Delta T is 10 C.		
FLUEHX	Heat exchanger. Delta T min = 10 C.		
CRACKER	Fired ammonia decomposition reactor modelled as 2 x RGIBBS reactors. CRACKER is ammonia decomposition reaction.		
FURNACE	Fired ammonia decomposition reactor modelled as 2 x RGIBBS reactors. FURNACE is hydrogen and trace ammonia combustion reaction		
SPLITTER	Separator to recycle some of ammonia decomposition reactor products to fire the furnace.		
Required Convergence			
SPLITTER	Recycle stream size converged to satisfy ammonia decomposition reactor constraints		
LIQFEED	Liquid ammonia feed mass flow rate converged to satisfy constraints of system output to gas turbine		
Results			
SPLITTER recycle %	20.5%	%	

Appendix C: LCOE Assumptions

Table C1: LCOE Techno-economic Assumptions

		Unit	Reference
General assumptions			
Plant size	1,000	MW	UK BEIS & Uniper [71]
Power plant capacity factor	25%	%	Identified as approximate capacity factor for technology required for 2°C decarbonization in [4]
WACC	7.5%	%	Standard used in IRENA for OECD and China [82]
CO_2 Price	140	USD/t CO_2	IEA advanced economies power sector forecasted CO_2 price in 2040 [1]
Fuel Price in 2040			
Natural Gas	8.9	USD/MMBTU	EU price forecast 2040 in IEA STEPS scenario [1]
Coal	78	USD/t	EU price forecast 2040 in IEA STEPS scenario [1]
Green Ammonia	380	USD/t NH_3	Figure 5a
Biomass	8.0	USD/GJ	ESME for Biomass imports mid-range 2050 [90]
Coal + CCS			
Supercritical plant fuel efficiency (LHV)	41%	%	Global CCS Institute [84]
CAPEX	2,328	USD/kW	Global CCS Institute [84]. No future progress assumed on Rankine cycle CAPEX or efficiency, in line with IEA [1]
Economic Lifetime	30	years	[90]
Plant fuel efficiency with CCS (LHV)	33%	%	Global CCS Institute [84]
CCS additional CAPEX	1,426	USD/kW	Global CCS Institute [84]
Fixed O&M with CCS	64,912	USD/MW/yr	Global CCS Institute [84]
Variable O&M with CCS	19	USD/MWh	Global CCS Institute [84]
Lifecycle emissions before CCS	797	kg CO_2/MWh	Average of Global CCS Institute [84] (774 kg CO_2/MWh) and IPCC [74] (820 kg CO_2/MWh)
Lifecycle emissions after CCS	159	kg CO_2/MWh	Average of Global CCS Institute [84] (97 kg CO_2/MWh) and IPCC [74] (220 kg CO_2/MWh)
Gas CCGT + CCS			
CCGT plant fuel efficiency (LHV)	60%	%	UK BEIS & Uniper [71]. No future progress assumed on GT CAPEX or efficiency, in line with IEA [1]
CAPEX	766	USD/kW	UK BEIS & Uniper [71]. No future progress assumed on GT CAPEX or efficiency, in line with IEA [1]
Lifetime	25	years	UK BEIS & Uniper [71]
Plant fuel efficiency with CCS (LHV)	53%	%	UK BEIS & Uniper [71]
CCS additional CAPEX	1116	USD/kW	UK BEIS & Uniper [71]
Fixed O&M with CCS	42,225	USD/MW/yr	UK BEIS & Uniper [71]
Variable O&M with CCS	11	USD/MWh	UK BEIS & Uniper [71]
Lifecycle emissions before CCS	490	kg CO_2/MWh	IPCC [74] including methane emissions CO_2 equivalent
Lifecycle missions after CCS	170	kg CO_2/MWh	IPCC [74] including methane emissions CO_2 equivalent.
CCS CAPEX reductions in future	30%	%	UK BEIS & Uniper [71]
Lifecycle emissions after CCS in future	94	kg CO_2/MWh	IPCC [74] minimum range of estimates for present day technology, including methane emissions CO_2 equivalent.
Ammonia CCGT			
CCGT plant fuel efficiency (LHV)	60%	%	Assuming same as NG [71]
CAPEX	766	USD/kW	Assuming same as NG [71]
Lifetime	25	years	Assuming same as NG [71]
Fixed O&M	17,353	USD/MW/yr	Assuming same as NG [71]
Variable O&M	5	USD/MWh	Assuming same as NG [71]
Ammonia CCGT with Cracker			
Cracker conversion	99%	% of NH_3	99% conversion at 850°C based on small-scale commercial crackers using nickel catalysts [54] [55]..
Cracker output recycle size	20.5%	% of output	Calculated using ASPEN Plus
H_2 separation losses	1%	%	Based on 80-85% recovery via H2 membrane [79] and tail gas used for recycle, so very small losses
Phase 1			
Cracker size	63.7	ton H_2/hr	Calculated using ASPEN Plus
Plant fuel efficiency with cracker (LHV)	53.8%	%	Calculated using ASPEN Plus
Cracker additional CAPEX	402	USD/kW	Calculated using Cracker cost curve from Figure 4
Phase 2			
Cracker size	17.3	ton H_2/hr	Calculated using ASPEN Plus
Plant fuel efficiency with cracker (LHV)	58.0%	%	Calculated using ASPEN Plus
Cracker additional CAPEX	152	USD/kW	Calculated using Cracker cost curve from Figure 4
Nuclear			
Fuel Cost	4	USD/MWh	World Nuclear Association [89]
CAPEX	4,500	USD/kW	EU CAPEX in IEA's 2040 forecast [1]
Economic Lifetime	30	years	[90]
Fixed O&M	100,000	USD/MW/yr	EIA [88]
Bioenergy with CCS			
BECCS plant fuel efficiency (LHV)	37%	%	ESME- biomass-dedicated steam turbine power station [90]
CAPEX	3,653	USD/kW	ESME [90]
Lifetime	30	years	ESME [90]
Fixed O&M with CCS	140,492	USD/MW/yr	ESME [90]
Variable O&M with CCS	7	USD/MWh	ESME [90]
Negative CO2 emissions	0.35	$GtCO_2$/EJ	Mean value from Fuss et al range of 0.02-0.05 $GtCO_2$/EJ [73]
Negative CO2 emissions (electricity)	342	kg CO_2/MWh	Calculated based on 37% efficiency

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