Missing Link to a Livable Climate

How Hydrogen-Enabled Synthetic Fuels Can Help Deliver the Paris Goals

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Acknowledgements

Missing Link to a Livable Climate: How Hydrogen-Enabled Synthetic Fuels Can Help Deliver the Paris Goals

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Contents

Executive Summary 1

1 The Carbon Gap 5

2 Hydrogen as the Missing Link 8

3 Next-Generation Advanced Heat Sources for Hydrogen Production 26

4 The Fuels Decarbonization Challenge 35

5 Total Investment Requirements 40

6 Cost Reduction from Shipyard Manufacturing 44

7 Physical Space Constraints: A Reality Check 52

8 Conclusions and Recommendations 59

A Appendix: Sources and Assumptions for Hydrogen Production Cost Estimates 63

Endnotes 66

Figures

Figure 1. IEA's stated policies scenario: world energy by source 6

Figure 2. Energy use in the 'difficult-to-decarbonize' sectors, 7

Figure 3. Relationship between capacity factor and cost of hydrogen 15

Figure 4. Relationship between energy system CapEx and cost of hydrogen 16

Figure 5. Relationship between electrolyzer efficiency and cost of hydrogen 17

Figure 6. Relationship between electrolyzer CapEx and cost of hydrogen 18

Figure 7. Current hydrogen production costs of different energy technologies 19

Figure 8. Current hydrogen production costs of different energy technologies in the UK 20

Figure 9. Oil price 'guardrails' of the hydrogen economy ($0.50–1.50/kg hydrogen) 21

Figure 10. Cost of hydrogen production from different energy technologies in the real world now and in 2030 22

Figure 11. Projected cost of hydrogen production from different energy technologies in 2050 24

Figure 12. Rendering of a hydrogen Gigafactory under construction 27

Figure 13. Another view of a hydrogen Gigafactory under construction 28

Figure 14. Rendering of ammonia bunker offloading ammonia from a production platform 31

Figure 15. Production platform for hydrogen, power, ammonia, and desalination moored near shore 33

Figure 16. Projected growth in 'difficult-to-decarbonize' sectors by 2050 35

Figure 17. Sectors of the economy that are 'addressable' with renewables-generated hydrogen to substitute for fossil fuels at different hydrogen production costs over time 36

Figure 18. Cumulative CO_2 emissions by 2050 showing the reduction achieved by substitution with renewables-only hydrogen as per Figure 17 (Compare with Figure 21) 37

Figure 19. Sectors of the economy that are 'addressable' with clean heat-derived hydrogen to substitute for fossil fuels at different hydrogen production costs over time 37

Figure 20. Fuel substitution in different sectors from ultra-cheap hydrogen generated by advanced heat sources 2020–2050 38

Figure 21. Net Zero carbon emissions 39

Figure 22. Cumulative investment in hydrogen-based fuels substitution to fully decarbonize fuels markets by 2050 40

Figure 23. Comparative investment for fuel substitution by 2050 41

Figure 24. Shipyard starts and cumulative operating shipyards 42

Figure 25. Additions and cumulative production facilities 43

Figure 26. Costs of recent nuclear plants 45

Figure 27. Cost reduction from first-of-a-kind (FOAK) to program build 46

Figure 28. Costs avoided through shipyard manufacture 47

Figure 29. Cost reduction from advanced heat source technology 49

Figure 30. Further cost reductions from ongoing design improvements and manufacturing process improvements 51

Figure 31. Evolution of cost reduction from first-of-a-kind construction projects to mass manufactured products 51

Figure 32. Comparing the total area required to replace the UK's current oil consumption with hydrogen generated from either wind, solar, or advanced heat sources 55

Figure 33. Comparing the total area required to replace Japan's current oil consumption with hydrogen generated from either wind, solar, or advanced heat sources 56

Figure 34. Comparing the total area required to replace South Korea's current oil consumption with hydrogen generated from either wind, solar, or advanced heat sources 57

Tables

Table 1. Capacity factors of different clean energy generation types 14

Table 2. Electrolyzer costs and performance assumptions 25

Table 3. Ammonia production platform output and physical specifications 31

Table 4. Detail on costs avoided through shipyard manufacture 48

Table 5. Cost reduction from shipyard manufactured light water reactors to advanced heat technology 50

Table 6. Calculations of energy production and hydrogen production for wind, solar, and advanced heat sources for the UK, Japan, and South Korea 53

Table 7. Annual oil consumption in the UK, Japan, and South Korea (2019) 54

Table 8. Sources and Assumptions for Hydrogen Production Cost Estimates (2030) 63

Table 9. Sources and Assumptions for Hydrogen Production Cost Estimates (2050) 65

Executive Summary

Executive Summary

As of this writing, the world is far off track for meeting the Paris climate goals of 1.5–2°C. Much of the carbon gap is because of the 'difficult-to-decarbonize' sectors such as shipping, aviation, and industry. Current projections still show fossil fuels making up the majority of world energy use by mid-century.

- If we miss the 1.5°C target, this means accepting climate impacts such as 10 million more people displaced by sea level rise, 65 million more people exposed to exceptional heatwaves, a doubling of biodiversity related impacts such as species loss, the elimination of Arctic Ocean sea ice, and the loss of virtually all coral reefs.
- If we miss the 2°C target, half the world's population would be exposed to summertime 'deadly heat,' Greenland and the West Antarctic ice sheets would collapse, droughts would increase by 500%, and the Sahara Desert would begin to expand into southern Europe. World food supplies would be imperiled, driving major refugee flows and a growing risk of civilizational collapse.
- Even current commitments to large renewable buildouts are insufficient to avoid pushing the world towards catastrophic climate outcomes, with a high risk of a 4°C outcome. This would mean substantial areas of the planet becoming uninhabitable to humans and a geological-scale mass extinction of life.
- The only known way to address the 'difficult-to-decarbonize' economic sectors is with the large-scale use of hydrogen as a clean energy carrier and as a feedstock for synthetic fuels such as ammonia. This can fully decarbonize aviation, shipping, cement, and industry using known and proven technologies. This would be a complement to all those renewables being deployed, not an alternative.
- For the hydrogen revolution to take place, hydrogen must be generated from non-fossil sources, at a price which is competitive with cheap oil. Based on our modeling, we estimate this price as $0.90/kg.
- Current projections for renewable-generated hydrogen estimate prices of $2.14–$2.71/kg by 2030, and $0.73–$1.64 by 2050. Price reductions are constrained by low capacity factors even though we expect capital expenditure costs for renewables to continue to fall dramatically.
- To achieve the lowest cost renewable-hydrogen, it is possible to co-locate wind and solar projects, in the best combined wind and solar resources, to deliver high capacity factors and hydrogen at around $2/kg within the 2030 timeframe. However, most of these locations are remote from populations and markets. Adding distribution costs from remote locations, for example, Australia to Japan, increases costs from $2/kg to $3.3/kg. This raises the cost beyond the threshold of economic competitiveness ($0.90/kg), which this report describes as essential to achieve widescale substitution of fossil fuels.
- Renewables are also constrained by physical space, especially if renewables are already assumed to do most of the heavy lifting for electricity decarbonization. Most countries will not be able to find the physical space for renewables-generated green hydrogen at the scale needed as well. (Maps illustrating physical space constraints are shown in Section 7.)

- By contrast, conventional nuclear can deliver clean hydrogen for as low as $2/kg in Asian markets today. We find that a new generation of advanced modular reactors, hereafter referred to as *advanced heat sources*, with new manufacturing-based delivery models, could deliver hydrogen on a large scale for $1.10/kg, with further cost reductions at scale reaching the target price of $0.90/kg by 2030. This is the only technology that can realistically achieve this low price from electrolysis in the short to medium term. Therefore, for the near term we are referring to advanced modular reactors, but in the longer term, *advanced heat sources* could also include fusion and high-temperature geothermal. These additional advanced heat sources could be designed as drop-in modules to the production platform architecture described in this report.
- These advanced heat sources can be built rapidly and at the required scale with a Gigafactory approach to modular construction and manufacturing or in existing world class shipyards. The Gigafactory-approach refers to a factory that manufactures dozens of reactors and other needed components that are then installed on the same site for highly efficient and low-cost scale production of hydrogen and other synthetic fuels. These Gigafactories can be located in port areas on existing brownfield sites, delivering high-paying jobs, often to depressed industrial areas. Just 10–12 Gigafactories would replace all of UK's natural gas consumption.
- Global rollout for hydrogen can be accomplished with shipyard-manufactured, sea-going, production platforms akin to the large offshore vessels currently used by the oil industry. Hundreds of these production platforms can be manufactured each year using existing spare shipyard capacity, delivering low-cost, high-volume H_2 production facilities to industrial centers around the world.
- Gigafactories and offshore plants can achieve hydrogen at production costs that allow deep decarbonization to be essentially completed by mid-century, by which time the world achieves net zero carbon emissions—"Net Zero". Such a program would avoid 400 gigatonnes (Gt) of cumulative CO_2 emissions that would be emitted in a renewables-only scenario, putting the world back on the 1.5/2°C pathway of the Paris Agreement goals. Thus large-scale, low-cost clean hydrogen is the 'missing link' to a livable climate.
- This massive decarbonization effort can be achieved with a relatively small physical and environmental footprint, allowing large areas of land to be spared for rewilding and the regeneration of natural ecosystems (potentially delivering additional carbon sequestration)—unlike the 'energy sprawl' associated with country-sized renewables industrial developments or extensive use of biomass energy. This improves other ecological concerns such as biodiversity as well as climate.
- The transition can be achieved with an investment of $17 trillion, spent over 30 years from 2020 to 2050. This is lower than the $25 trillion investment required to maintain fossil fuels flows in future decades. This contrasts with a $70 trillion investment for a similarly sized renewables-to-fuels strategy, sited in the world's major deserts, assuming that is even possible.
- The approach outlined in this report can thus decarbonize the economy and deliver Net Zero at a cost lower than that required to maintain fossil fuels. However, this transition will not begin without urgent action by governments and other actors to bring down costs and accelerate innovation and deployment. Innovative heat sources need to be fully brought into the world's decarbonization efforts.

Why You Should Read This Report

Intended audiences for this report include:

- Analysts focused on the potential for clean hydrogen to accelerate decarbonization. This report is an urgent call to action to address and act upon the gaps in the literature, where advanced heat technologies are either drastically under-represented, or entirely omitted, from the range of clean production options.
- Policy makers working on climate, hydrogen, heat, and energy transitions investing effort and resources, including market incentives, ought to give due weight to the full range of options available.
- Climate and energy modelers can broaden the range of decarbonization pathways through the inclusion of a broader set of technology options. Having more options both alleviates pressure elsewhere in the system and creates new opportunities. Mapping believable, achievable pathways to zero carbon emissions and growth is a critical part of mobilizing investors, supply chains, policy makers, and the public for success.
- Climate hawks taking seriously the mainstream projections for fossil fuels making up 50–60% of energy use in 2050 should be demanding action across the full range of options available to prevent this outcome.
- Producers, distributors, and consumers of liquid fuels in the shipping, aviation, and oil and gas industries will be interested to learn that they can use existing infrastructure and business models to continue powering civilization, affordably and without emissions.
- Industrial users of hydrogen, current and future, such as oil refineries, ammonia, steel, and biofuels producers will be presented with opportunities to achieve a cost-competitive and clean industrial transition.
- Industry innovators with enlightened perspectives and other mobilizing forces within the industry should seize upon the concepts presented in this report as opportunities to both modernize the industry and expand the value proposition to enable advanced technologies to make a meaningful contribution towards decarbonization and increased global energy access within mid-century timescales.

Main Report

1

The Carbon Gap

The world is currently far off track from emissions trajectories needed to meet the Paris goals. Conventional projections suggest that—even with a massive build-out of renewables and the near-complete decarbonization of electricity grids—fossil fuels will still comprise 75% of global energy by mid-century. This puts us on the path of 3–4°C climate heating, with catastrophic impacts on society and ecosystems. There is currently no credible plan for addressing this 'carbon gap'.

1.1 Climate Targets and Carbon Budgets

In the 2015 Paris Agreement world leaders set a target for holding global heating well below 2°C and pursuing further efforts to limit warming to 1.5°C. According to the Intergovernmental Panel on Climate Change (IPCC), in order to meet a 1.5°C pathway with no overshoot, anthropogenic CO_2 emissions must decline by half by 2030 and reach net zero carbon emissions—"Net Zero"—by 2050. For a 2°C pathway, Net Zero must be reached by 2070.

Another way of visualizing the challenge is in terms of cumulative carbon budgets. For a 1.5°C outcome (with 66% probability) the IPCC estimates that the remaining carbon budget in 2017 stood at 420 $GtCO_2$ (billion tonnes of carbon dioxide).[1] With current global annual emissions of approximately 42 $GtCO_2$, this means the entire 1.5°C budget will have been burned by the end of this decade even if emissions do not rise further. A recent paper in Nature found that committed lifetime emissions from existing infrastructure (coal and gas plants, industry, cars, aircraft, etc.) already exceed this 1.5°C budget, and that two-thirds of the 2°C budget is already committed.[2]

There is a stark contrast between this urgent carbon calculation and conventional energy use projections. According to the International Energy Agency (IEA), current government 'Stated Policies'—while leading to a large growth in renewable energy generation—still result in a higher use of fossil fuels by mid-century than today. This increase in fossil fuel use is largely due to economic and population growth in developing countries. With huge global disparities in wealth, and 840 million people around the world today still not having access to electricity, energy demand in this projection rises by 1% a year with CO_2 emissions not reaching a peak even by 2040 (See Figure 1 on the next page). According to the IEA's description of this mainstream scenario:

> *Low-carbon sources, led by solar photovoltaics (PV), supply more than half of this growth, and natural gas, boosted by rising trade in liquefied natural gas (LNG), accounts for another third. Oil demand flattens out in the 2030s, and coal use edges lower. Some parts of the energy sector, led by electricity, undergo rapid transformations. Some countries, notably those with "net zero" aspirations, go far in reshaping all aspects of their supply and consumption. However, the momentum behind clean energy technologies is not enough to offset the effects of an expanding global economy and growing population. The rise in emissions slows but, with no peak before 2040, the world falls far short of shared sustainability goals.* (IEA 2020)[3]

This carbon gap does not only preclude the possibility of staying below 1.5°C or even 2°C. According to the Climate Action Tracker current government policies lead to a likely outcome of 3°C, with global heating as high as 4.1°C possible.[4]

1.2 Climate Impacts

Abandoning the 1.5°C target for a worse 2°C outcome means accepting increasingly serious climate impacts. According to the IPCC, these include 10 million more people displaced by sea level rise, 65 million more people exposed to exceptional heatwaves, a doubling of biodiversity-related impacts such as species loss, the elimination of Arctic Ocean sea ice, and the loss of virtually all coral reefs.[5]

Allowing temperatures to rise by 3°C would mean climate impacts becoming increasingly catastrophic. According to a recent review of the science,[6] at 3°C half the world's population would be exposed to summertime 'deadly heat,' Greenland and the West Antarctic ice sheets would collapse, droughts would increase by 500%, and the Sahara Desert would begin to expand into southern Europe. World food supplies would be imperiled, driving major refugee flows and a growing risk of civilizational collapse.

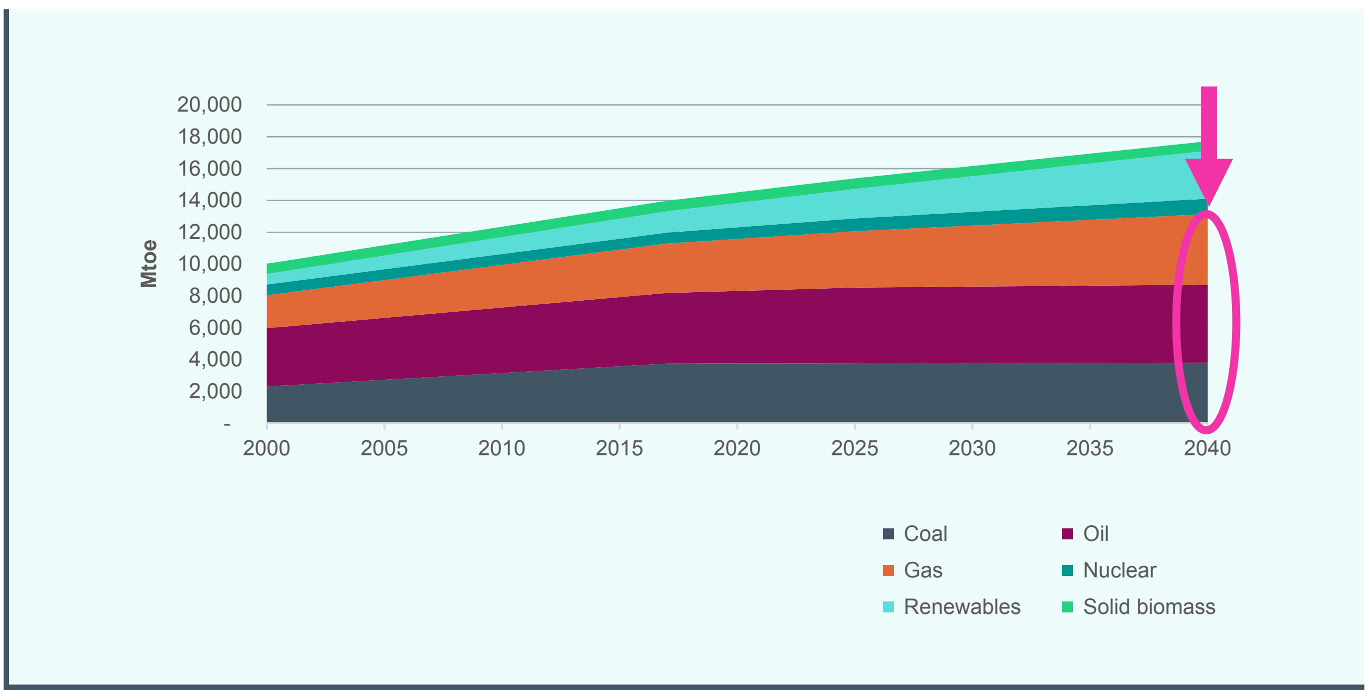
At 4°C, large areas of the tropics and sub-tropics would become biologically uninhabitable to humans, including much of the Middle East, the Indian sub-continent, Africa, and south and east Asia. There would be synchronous harvest failures in the world's major breadbaskets as temperatures cross thresholds lethal to most crops. In other words, we would be gradually making our planet unlivable.

1.3 Fossil Fuels Continue to Dominate

Current world oil and gas consumption is equivalent to 100 million barrels per day (219 exajoules EJ per year), and this is projected to continue to grow through mid-century and beyond. The IEA's "Stated Policies Scenario," aggregating current government policies around the world on energy (and extrapolated by us to 2050), sees total oil and gas consumption growing to 350 EJ per year (see Figure 2).

Although this scenario includes substantial growth in renewable generation for electricity, accompanied by a major electrification of surface transport, the IEA projects that fossil fuels will continue to supply 75% of primary energy by 2040. Figure 1 below shows the IEA's projection of their "Stated Policies Scenario" for primary energy by source through 2040, with fossil fuel sources circled in pink.[7]

Figure 1. **IEA's stated policies scenario: world energy by source**



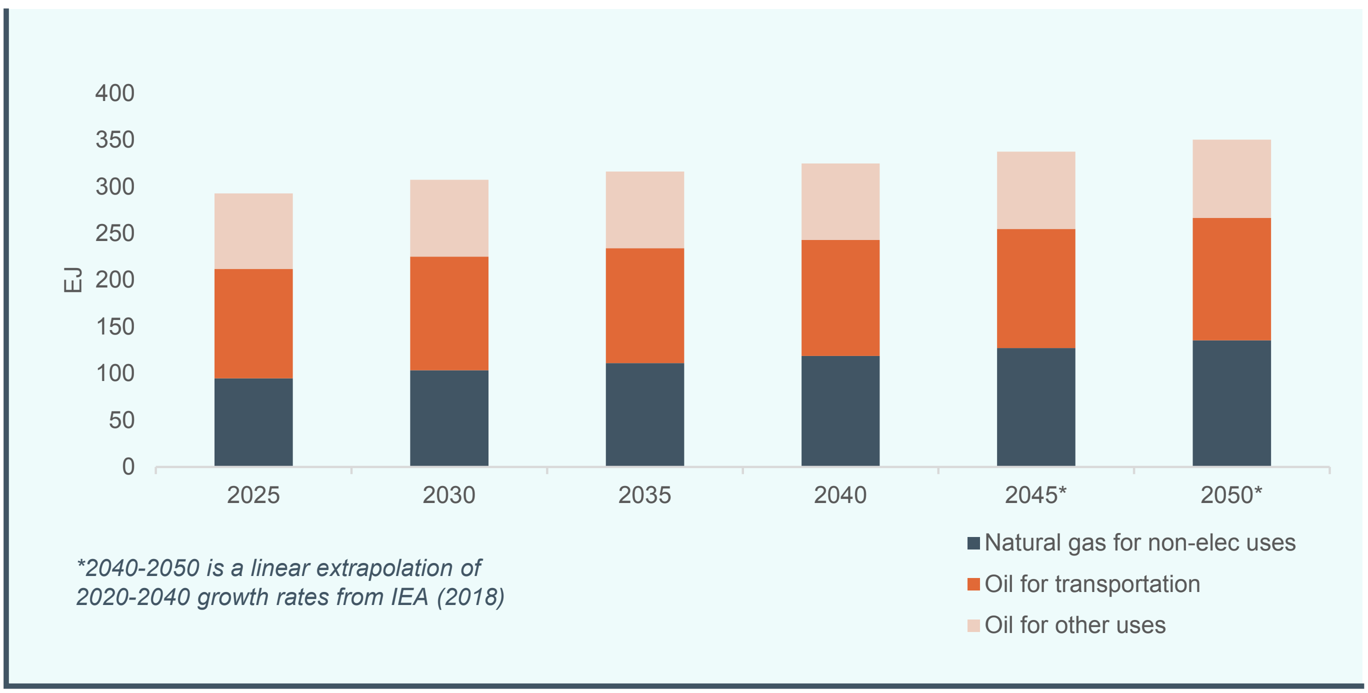
Much of this remaining fossil fuel consumption comes in so-called ‘difficult to decarbonize’ economic sectors such as aviation, heavy industry, marine shipping, and non-electricity uses of gas such as for domestic heating. While coal and natural gas for electricity generation are relatively easy to substitute with clean energy replacements, liquid fuels are much more difficult to decarbonize. Indeed, liquid fuels uses comprise the majority of remaining emissions by mid-century.

1.4 The Decarbonization Challenge–the ‘Missing Link’ to 1.5/2°C

According to conventional projections, emissions in the ‘difficult-to-decarbonize’ parts of the economy will still be responsible for 20 gigatonnes (Gt)[8] of annual emissions in 2050. (To restate: these do not include sectors like electricity, which are supposedly ‘easy to decarbonize’ and therefore considered fully carbon-free by mid-century.) Cumulatively, over the period from 2020 to 2050, the remaining carbon-intensive sectors emit 525 Gt of CO_2 emissions—100 Gt more than the total remaining carbon budget for the 1.5°C pathway. Given that hundreds more gigatonnes of fossil fuel emissions are still in the pipeline from the electricity sector, this scenario also puts 2°C out of reach. Figure 2 shows the expected growth in these sectors.

There is currently no plan for how the difficult-to-decarbonize sectors will be addressed, with most 1.5°C pathways in climate models dependent on massive negative emissions post-2050 in order to make up for this gap. This is little more than a convenient magic wand—there are currently no technologies available that could sequester billions of tonnes per year of CO_2 for many decades. Our only hope of getting back onto a pathway compatible with the Paris agreement is therefore to rapidly develop and scale up zero-carbon technologies to address the difficult-to-decarbonize sectors. We turn to the most promising option—hydrogen—next.

Figure 2. **Energy use in the ‘difficult-to-decarbonize’ sectors**[9,10]



2 Hydrogen as the Missing Link

Hydrogen has long been touted as the ideal replacement for fossil fuels, yet decades of hopes have so far not lived up to reality. Even so, hydrogen has some inherent advantages that are now coming into play more forcefully than ever before. Most importantly, hydrogen is a molecular fuel that burns without producing carbon dioxide, and thus does not contribute to climate breakdown. Hydrogen is also scalable: it is derived from water, and burns back into water, meaning the reservoir of hydrogen is essentially inexhaustible and can never be used up. It can be 'burned' either through combustion or in a fuel cell to produce electricity, and hydrogen-based fuels are energy dense, carrying much more energy per unit of mass than competing technologies like batteries. In this section we explain how hydrogen can substitute for fossil fuels, and what the economics need to be to drive this transition to a hydrogen economy.

2.1 Hydrogen Basics

Hydrogen is not really a fuel—it is more properly described as an energy carrier since it does not occur in free form on Earth, and therefore unlike fossil fuels cannot be mined or drilled and burned directly. Hydrogen needs to be liberated from where it is bound to other molecules, such as methane (CH_4) or water (H_2O) so that it can carry this energy in liquid or gaseous form for future combustion.

Producing hydrogen from water is clean and easy. This is done via a process called electrolysis, where an electric current is passed through water, such that hydrogen and oxygen bubble off separately. However, electrolysis of water requires the input of large amounts of energy to break the strong molecular bonds of H_2O. The process is only 60–76% efficient, and further energy losses occur when hydrogen is stored, compressed, or converted to other fuels. Fuel cells and combustion also generate further losses, so the round-trip efficiency of hydrogen (from electricity in electrolysis back to electricity in a fuel cell or an engine) can be surprisingly low: at best 45% and at worst 16%.[11] This is why direct electrification of sectors like transport (via electric cars) will always be more efficient than a hydrogen-centered approach which turns electricity into hydrogen and then back again.

As a very small molecule, hydrogen is also prone to leakage from conventional pipelines and storage facilities, and its flammability makes leaks a serious safety concern. Hydrogen can however be added to natural gas pipelines to reduce the carbon intensity of gas applications like cooking and heating, though hydrogen-only pipelines would require both better pipes and different end-usage appliances. Hydrogen can be stored directly in highly pressurized containers, but only in small volumes and for short times. Much larger quantities of hydrogen can be stored in underground salt caverns; however, these are only available in a few geographical locations.

Hydrogen also has a low volumetric density, both as a gas and as a liquid. For example, a cubic meter of methane has eight-times more mass—and therefore packs more energy punch—than a cubic meter of hydrogen. To liquify hydrogen at atmospheric pressure it has to be cooled to below -253°C, just 20°C above absolute zero (-273°C) and 90°C below the boiling point of liquefied natural gas. Converting hydrogen to liquid for transport requires very high pressures, and therefore takes a substantial amount of both energy and engineering, further reducing efficiencies. Even as a liquid, hydrogen is not very dense: a cubic meter of liquid hydrogen contains 71kg of hydrogen, while water contains 111kg. This is because of differences in how tightly hydrogen atoms can be packed via different molecular bonds.

The volumetric advantage of larger molecules also applies to hydrocarbons. For example, a cubic meter of heptane (C_7H_{16}) contains nearly three-times as much hydrogen as a cubic meter of liquid hydrogen. Given that heptane combusts easily (unlike water, which is at a lower thermodynamic energy state and therefore cannot combust), this helps explain why the energy density of hydrocarbons as liquid fuels in the modern economy will be so difficult to replace—even directly with liquid hydrogen. Hydrocarbons are both very energy dense, and easy to transport because they are mostly liquid at room temperature.

However, even with its lower energy density liquid hydrogen is still approximately a hundred-times more energy-dense than lithium-ion batteries. This two-orders-of-magnitude difference is due to fundamental physics, so even substantial future improvements in battery efficiency will not change this picture significantly. This therefore rules batteries out for applications like intercontinental aviation, shipping and other forms of long distance transport which require more energy dense fuels.

This last factor is why hydrogen may finally be coming of age. While a large portion of the decarbonization challenge can be carried out using electrification (with the electricity generated from zero-carbon sources such as solar, wind, nuclear, and hydro), there are certain energy end-uses which electrification is unlikely to serve well for the foreseeable future. Short of major technological transformations, hydrogen-based liquid fuels therefore offer a decarbonization option which can drive carbon out of these otherwise difficult-to-decarbonize sectors on the timescales—years rather than decades—required to avoid catastrophic climate heating.

2.2 Enter Ammonia

The difficulties in transporting and storing elemental hydrogen mean that chemical compounding—combining hydrogen into denser molecules—is going to be a better option in most cases. Carbon combines well with hydrogen, as we can all see with the extensive use our economy makes of fossil fuels. However, combusted hydrocarbons are not an option—we can, and must, eliminate the need to pump additional hydrocarbons from underground.

The only way to get around this carbon scarcity (not taking carbon from underground and putting it in the atmosphere) is to use atmospheric CO_2 as a reservoir of carbon for the creation of synthetic fuels. However, this in turn raises several challenges inherent in the basic physics. Like water, CO_2 is at a lower thermodynamic energy state—it is a product of combustion, so by definition cannot be combusted again. Therefore, a lot of energy needs to be added to split the carbon from the oxygen atoms and then recombine them with hydrogen into a higher energy state. Carbon dioxide is also very diffuse in the atmosphere (at 400 parts per million or 0.04%) so capturing it from the air to use as a feedstock is both energetically expensive and inefficient. Even so, many innovators are pursuing the idea of producing synthetic hydrocarbons from air-captured CO_2 because of the potential usefulness of zero-carbon hydrocarbons as 'drop-in' fuels for existing applications.[12]

Biofuels for Aviation

One very specific opportunity could be to use hydrogen to enhance biofuels. This means taking more concentrated carbon from vegetation biomass rather than using diffuse atmospheric CO_2 as a source. A lot of the carbon in biomass is released in the production of conventional biofuels, making the scarcity of land on which to produce biofuels a fundamental social and ecological limitation. However, the energy yield of biofuels can be increased by as much as three times if hydrogen is added during the Fischer-Tropsch conversion process, dramatically increasing the scale of sustainable biofuels that can be produced at reasonable costs.[13]

Depending on end-product and process, the hydrogen cost would need to be below $2.30–$3 per kg to make this process competitive with biofuels without hydrogen enhancement. To indicate scale, one estimate is that 92 one-gigawatt nuclear reactors would be required to provide the hydrogen to produce 1 million barrels of diesel fuel per day from biomass.[14] Jet fuel demand globally currently averages around 8 million barrels per day.[15]

If this use of biofuels were restricted to only kerosene Jet A fuel for aviation, assuming drop-in hydrocarbon fuels are essential if the current aircraft fleet is to be maintained, it is conceivable that biofuels could decarbonize the aviation sector without overly serious negative land use and food displacement effects. However, biofuels use would have to be restricted to this sector only.

A much more proven option is to combine hydrogen with nitrogen—which is very easy to source as it makes up nearly 80% of the air around us. The most obvious chemical combination is ammonia, or NH_3, which combines one atom of nitrogen with three atoms of hydrogen. Ammonia is already produced in large quantities around the world as a feedstock for fertilizers, and the technology to produce ammonia from hydrogen and nitrogen—known as the Haber-Bosch process—has been in use for more than a century. Ammonia solves both the density and transport problems: it is liquid at close to atmospheric pressure and stores nearly twice as much hydrogen per cubic meter as liquid hydrogen does. One liter of ammonia stores as much energy as 1000 liters of hydrogen gas.

Ammonia can be burned in existing ship engines with only small modifications. Ammonia fuel cells can also power electric motors, allowing this versatile molecule to potentially decarbonize long-distance transport in multiple sectors, from aviation to heavy trucks and trains. Because of the ease of storage, ammonia can be (and already is) stored cheaply in large quantities. One problem is the generation of nitrous oxides—which are strong greenhouse gases—when ammonia is burned in air, but this can be managed with existing widely used catalytic converter technology.

This combination of factors mean that hydrogen and ammonia can together offer the prospect of tackling the difficult-to-decarbonize sectors of the economy. Hydrogen by itself can be used in industrial processes such as iron and steel-making, while ammonia can offer a decarbonization route for aviation, shipping, and other energy-intensive sectors.

In reviewing recent reports on hydrogen as a decarbonization solution,[16] we found that the number of countries with policies that directly support investment in hydrogen technologies and potential market applications is growing. A wide range of sectors are increasingly being targeted for policy support, R&D investment and finance for innovation and commercialization, with the majority focused on transport applications and gas networks.

2.3 Clean Hydrogen Must be Cheap

For hydrogen and ammonia to substantially contribute to decarbonizing the economy, the hydrogen that is used as a feedstock or a fuel has to be produced cleanly. This is not currently the case: almost all the hydrogen that is produced around the world is generated by a process called 'steam methane reforming,' which uses methane as a source of heat and hydrogen and therefore releases CO_2. Less than 1% of the hydrogen used today is 'clean'—the rest is considered 'grey', because it comes from unabated fossil fuels.[17] The IEA estimates that global hydrogen production currently releases 830 million tonnes of CO_2 per year, equivalent to 2.2% of energy-related emissions.[18] This makes hydrogen production on its own a significant contributor to global warming, with higher annual emissions than, for example, Germany.

The reason why almost all the world's hydrogen is derived from fossil fuels is straightforward economics. With cheap natural gas and often no meaningful price on carbon emissions, hydrogen can currently be produced for as little as $1/kg via steam methane reforming. In contrast, the cost of hydrogen from renewable-only electricity using electrolysis is above $4/kg, according to Bloomberg New Energy Finance (BNEF).[19] To compete in existing 'grey' hydrogen markets and enable clean synthetic fuels—the 'missing link' to a livable climate—clean hydrogen must be price competitive with that produced from fossil fuels.

This transition cannot be endlessly dependent on policy and subsidies. To use the analogy of the Impossible Burger™, this popular food innovation has not been a success because politicians imposed a tax on beef, but because it offered an environmentally superior substitute product at a price which matches conventional meat burgers. Similarly, hydrogen-based clean fuels will be able to displace fossil fuels on the scale required only when they offer an equivalent (zero carbon) energy service at a comparable or lower price than oil and gas do today.[20]

According to BNEF, renewable-derived hydrogen—with sufficient innovation and investment—might reach production costs between $2.14–$2.71/kg by 2030, and $0.73–$1.64 by 2050.[21] If this analysis is correct, clean hydrogen from renewables will not enable cost-competitive synthetic fuels until as late as mid-century, preventing it from playing any significant role in efforts to avoid catastrophic climate outcomes. It is therefore a risky bet to insist that only renewables should be considered as an energy source for hydrogen production. If we only use wind and solar, the clean energy transition could (at worst) be stillborn, and (at best) begin much too late to help the climate.

The necessary amount of hydrogen cannot be produced, as some have suggested, using surplus renewables-derived grid electricity. This is not just because of scale, although that is the most obvious reason, but because once utilized, surplus electricity is no longer surplus, and therefore will attract a price. Hydrogen production would therefore always need to compete on price terms with grid supply for scarce electricity. Given that the potential hydrogen market is much larger than our current electricity use, it obviously makes no sense to design it to run as small sub-section of electricity generation.

Another option might be to continue using hydrogen derived from fossil fuels, but to sequester the CO_2 underground using carbon capture and storage technologies (CCS). This is perhaps a viable substitute for today's relatively small scale of dedicated hydrogen production. It is not scalable however to the extent that would be needed if hydrogen and ammonia are to replace today's hydrocarbon liquid fuels market, in which case we would need to be pumping carbon dioxide back into the ground at a larger global scale than the entire oil and gas industry is currently pumping fossil fuels out of it.

The scale of the challenge to replace carbon-based liquid fuels in the modern economy is truly daunting, far larger than most people realize. Indeed, the ultimate size of the zero-carbon hydrogen market—if expanded to produce synthetic substitutes for the projected 350EJ of fossil fuels—the energy value of those substitutes would be 4.2-times the size of today's entire 84EJ electricity market. Due to this scale of the challenge, and the equally vital issue of cost, we need the viable technology pathways that can deliver cost-competitive hydrogen at a global scale.

2.4 Hydrogen from Advanced Reactors

Advanced fission reactors are heat sources that produce electricity at very high efficiencies and can reliably deliver large amounts of high temperature (>500°C) steam to industrial end users. Given these attributes and with projected capacity factors of over 90%, advanced heat source technologies are uniquely suited to support the production of low-cost hydrogen at a global market scale. While this reality has been missing from the recent mainstream literature, this pathway to hydrogen has been researched and developed for decades at multiple national laboratories and private companies using conventional (light water) or more recently advanced reactors.

Over the decades many countries have explored a variety of options for using heat from reactors to meet a significant portion of the energy demand of the chemical process industry in general, including hydrogen production.

In the 1960s, the Japanese energy and steel industries worked together on major R&D efforts to provide hydrogen for steel production, where it could replace coke in iron ore processing. Today, that effort has expanded to further define the role of clean hydrogen production technologies to help Japan transition to a hydrogen economy which will include a move to fuel cell vehicles.

From the mid-1960s through the early 1980s, the Joint Research Centre in Ispra, Italy, one of Europe's leading research campuses, led a major effort to identify and screen innovative candidate processes for emissions-free hydrogen that included promising laboratory testing, corrosion studies, and designs for the full-scale equipment required for hydrogen production.

In the U.S., at the Gas Technology Institute investigated nuclear-driven hydrogen production. Privately, Westinghouse performed its own development of a 'hybrid sulfur process' in the 1970s.

A broad-based consortium of German industry supported an extensive national initiative to design and deploy high temperature gas reactors to provide process heat for hydrogen production in the 1970s and 1980s.[22] The program included, for example, building and operating two prototype reactors (AVR and THTR). Total investment in the program, including specific funding in support of hydrogen production, was approximately US$6 billion (2020 dollars).

By 1979, General Atomics, a U.S.-based company that designed and licensed a low-cost high temperature gas-cooled reactor and sold ten units to US utilities before the Three Mile Island accident, had constructed a laboratory-scale prototype of a 'thermochemical' process for producing hydrogen (known as the S-I or sulfur iodine process). A similar program in Japan at JEARI (now JAEA) included demonstration of laboratory scale hydrogen production with S-I in 1999. This was part of the larger high temperature test reactor (HTTR) program which had a specific mission of coupling clean energy to hydrogen production using both steam-methane reforming or the S-I process. An S-I system capable of 100-times the production rate of the JAEA laboratory scale system was built in the U.S. under the international I-NERI program[23] and commissioned at General Atomics in 2007.

By 2002, international cooperation on clean hydrogen was growing, partly as a result of increasing concerns over climate change. More than $600 million has been spent on projects under the international Generation IV International Forum (GIF) program, much of which was focused on integrating advanced nuclear heat sources with efficient hydrogen production processes using either high temperature heat or electricity.

By the mid-2000s, many advanced economies had a clean hydrogen program. The benefits and value of advanced nuclear heat sources as a pathway to cost-effective and environmentally friendly hydrogen production was being enthusiastically embraced by an international community of suppliers, end-users, and governments. In the U.S., the Energy Policy Act of 2005 mandated a national initiative to build an evolutionary high temperature gas reactor by 2021 called the Next Generation Nuclear Plant (NGNP), with approximately 10% of the energy being used to demonstrate carbon-free hydrogen production at a large scale.

In China, progress on high temperature reactors and plans to produce clean hydrogen with them has continued. Their first large high temperature gas reactor (HTGR) unit will come online in 2021 or 2022 at Shidao Bay. In the U.S., the Department of Energy recently launched three first-of-a-kind projects, each with a commercial electric utility partnering with the Idaho National Laboratory, to adapt existing, depreciated plants to make carbon-free hydrogen by electrolysis.[24]

One reason for the relatively slow progress in developing emissions-free hydrogen has been the rising cost of constructing new light water reactors (LWRs) in the U.S. and other Western countries, and the lack of any R&D or innovation focus on addressing the factors that were driving up the cost of new-build plants. These broader industry problems, along with other shifts in government energy policies, constrained investment in the development of advanced high temperature heat sources, the technology most suited to hydrogen production.

The difficulty of restarting the construction industry in the West for large LWRs is compounded by the dramatic reduction in the price of natural gas in countries like the U.S. Low gas prices not only tempered the enthusiasm for innovative hydrogen investment but lowered the cost of hydrogen production from fossil fuels, further increasing the perceived cost gap between clean hydrogen and hydrogen from natural gas.[25]

Today, something that should be quite obvious—the fact that advanced heat sources are uniquely suited for clean hydrogen production—has been forgotten or ignored by many. To drive a massive increase in clean hydrogen production and the deep decarbonization it enables, we need to restart the clean hydrogen discussion in earnest.

While the physics are favorable, the economics remain an open question. Therefore, in the next section, we examine the cost drivers underlying the price of clean hydrogen, and propose a pathway using advanced heat sources to deliver ultra-low-cost hydrogen at the required price of less than $1/kg. This would enable global-scale production of zero-carbon hydrogen and synthetic liquid fuels for aviation, shipping, and industry, putting the world on the path towards net zero carbon emissions—”Net Zero”—by 2050.

2.5 The Path to Low-Cost, Clean Hydrogen

Several analyses have examined potential zero-carbon hydrogen production costs from a range of electricity sources.[26] For this analysis, we reviewed these studies and combined some key results with our modelling of different reactor and hydrogen production pathways. We benchmarked these results with the IAEA’s Hydrogen Economic Evaluation Program (HEEP) model to compare these advanced heat sources’ performance against relatively aggressive assumptions for future solar PV and wind costs based on National Renewable Energy Laboratory’s (NREL) Annual Technology Baseline (ATB).

We find that the main drivers of clean hydrogen costs are:

- Capacity factor of the energy supply
- Capital cost of the energy supply
- Efficiency of the electrolysis / conversion
- Capital cost of electrolyzers

In following sections, each of these drivers and their overall contribution to the cost of hydrogen are examined.

2.6 Capacity Factor of Energy Supply

Capacity factor (CF) is a metric that describes the ratio of actual electrical energy generated over time to the maximum possible generation over the same period. Table 1 below shows how capacity factor affects the total amount of energy that is produced with some example clean energy sources. The number of megawatt-hours (MWh) produced is calculated by multiplying the capacity factor—the average production in MW—with the number of hours in the year (8,760).

Table 1. **Capacity factors of different clean energy generation types**

Generation Type	Example Project Size (MW)	Capacity Factor Range (U.S. Average)	Energy Production based on U.S. Average Capacity Factor (MWh)
Solar PV	100	15–27% (20%)	175,200
Onshore Wind	100	20–45% (35%)	306,600
Hydro	100	35–60% (42%)	367,920
Offshore Wind	100	28–55% (43%)	376,680
Biomass	100	59–65% (62%)	543,120
Geothermal	100	80–90% (85%)	744,600
Nuclear	100	87–93% (90%)	788,400

Sources:

The National Renewable Energy Laboratory, NREL Annual Technology Baseline (2019).

U.S. Energy Information Administration, U.S. EIA (2020). Table 6.07.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels.

Our cost modeling shows that capacity factor is the single biggest driver of hydrogen production cost, as demonstrated by the shape of the curve in Figure 3 on the following page. This shows that with other factors held constant (see below for what these are), a move from 90% capacity factor (nuclear) to 20% capacity factor (solar) can almost triple the cost of hydrogen. Moving from 90% capacity factor (nuclear) to 40% capacity factor (offshore wind) doubles the cost.

Figure 3. **Relationship between capacity factor and cost of hydrogen**

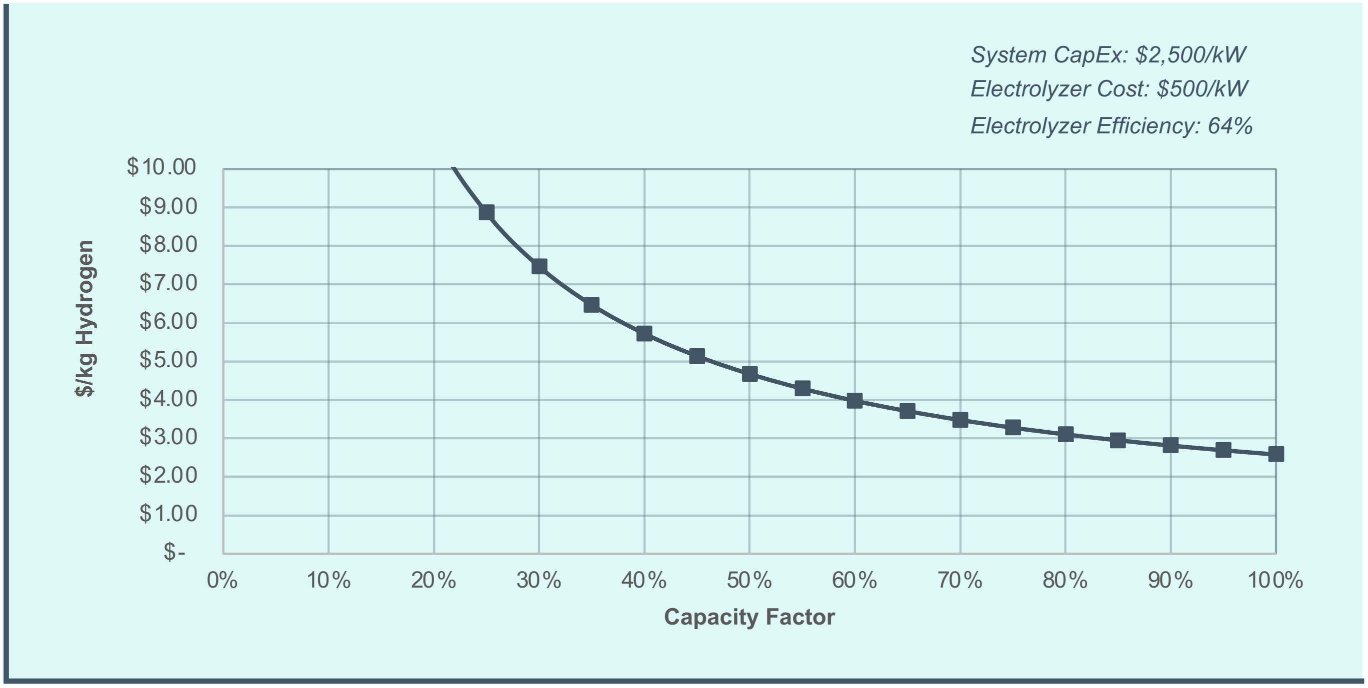
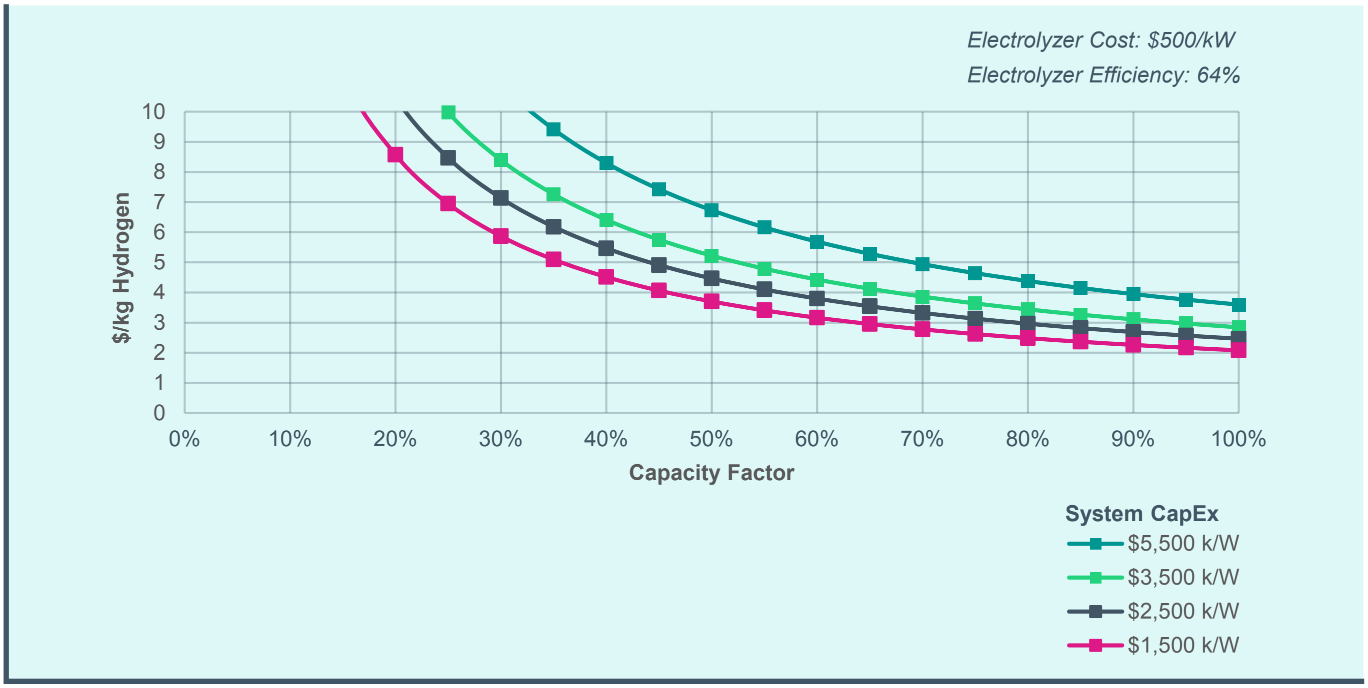


Figure 3 above demonstrates why using electricity from curtailed renewables (e.g., excess wind during windy days when turbines produce more than the grid can absorb) is not a viable option. Intermittent use of variable generation results in extremely low capacity factors and thereby very poor economics—the left-hand end of the curve in Figure 3. Hydrogen can never displace fossil fuels using this model.

2.7 Capital Cost of Energy Supply

After capacity factor, capital expenditure (known as CapEx) of input energy generation infrastructure has the next biggest impact on the cost of hydrogen. Capital expenditure is the amount of money that needs to be spent in order to build energy-generating infrastructure like wind turbines, solar farms, and power plants. Figure 4 on the next page shows that the difference between the lowest CapEx cost ($1,500/kW) and the highest CapEx cost ($5,500/kW) is an almost doubling of the cost of hydrogen. This relationship holds because a high CapEx on energy input makes energy more expensive during the operating lifetime of the plant.

Figure 4. **Relationship between energy system CapEx and cost of hydrogen**



Note that Figure 4 shows three different parameters: CapEx of energy, cost of hydrogen and capacity factor. Thus, for example, a high-cost source of energy—such as a US/EU new-build plant at a cost of $5,500/kW—operating at 90% CF has similar hydrogen production cost to a low-cost wind turbine ($1,500/kW) operating at a typical 45% offshore CF. Both plants produce hydrogen for roughly $4/kg.

2.8 Efficiency of Electrolysis

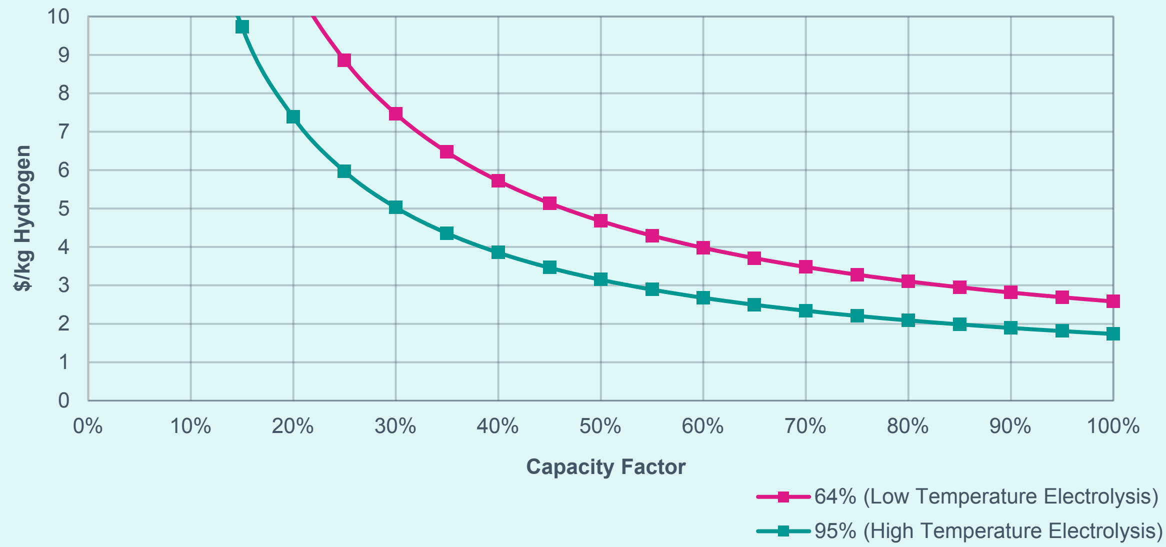
Electrolysis is the passing of an electric current through water in order to generate pure hydrogen gas (and oxygen as a by-product). This is conducted through the use of an electrolyzer. The efficiency of electrolysis—how much energy is lost in the process of converting electricity into hydrogen, in other words—is also an important driver of hydrogen cost.

Existing low-temperature electrolyzers (such as Alkaline and Proton Exchange Membrane technologies) typically have efficiencies in the low 60s (%).[27] High-temperature electrolysis, using heat to improve the efficiency of electrolysis can achieve higher efficiencies, but requires a high temperature heat source. Renewables like solar PV and wind produce electricity, not heat. The best efficiencies can be achieved by using heat directly to split water using thermochemical reactions. However, these need temperatures of close to 1000°C, which can only be produced by specially designed high-temperature reactors (or combustion of fuels, which makes no sense here).

Even if electrolyzers rather than thermochemical approaches are used, the combination with 500°C+ temperatures achieved by next-generation heat sources can dramatically improve efficiencies. High-temperature electrolysis consumes less electric power (with high-temperature steam, electrical efficiency is close to 100%) and more heat than conventional electrolysis, which leverages both the advanced reactor's electricity and high-temperature heat production. Notably, there are companies (e.g., Sunfire GmbH) marketing high-temperature electrolyzers and our scenarios assume that they will be deployable at the required scale.

Figure 5 below shows how electrolyzer efficiency affects cost, interacting with capacity factor and CapEx. The difference in hydrogen production cost for 64% and 95% electrolyzer efficiency at high capacity factor is approximately $1/kg. At lower capacity factors, this difference grows to $1.5–$3/kg of hydrogen.

Figure 5. **Relationship between electrolyzer efficiency and cost of hydrogen**



2.9 Electrolyzer Capital Cost

Electrolyzers that are sufficiently large to produce hydrogen at the scale required will require significant capital expenditures, therefore the CapEx of electrolyzers is also an important factor in the production cost of hydrogen. This is not as critical as the other three cost drivers above, however. It is particularly true at higher capacity factors.

Figure 6. **Relationship between electrolyzer CapEx and cost of hydrogen**

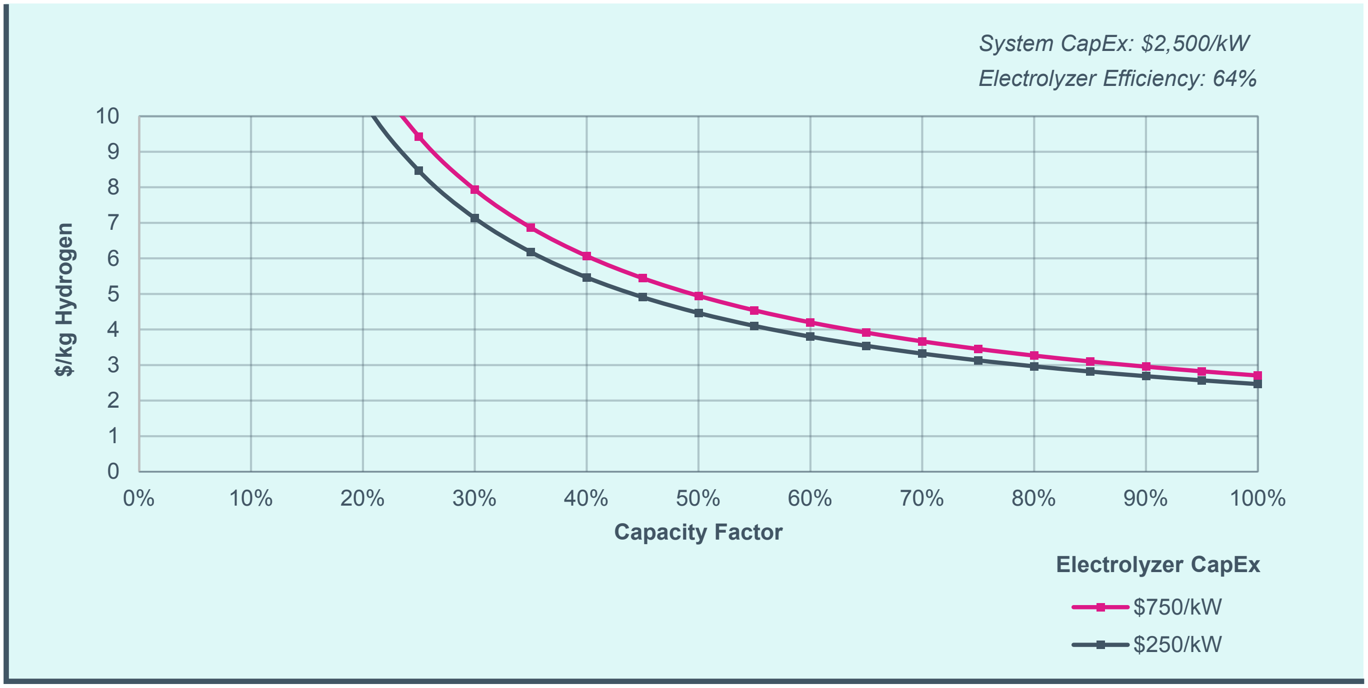


Figure 6 shows that the CapEx cost of electrolyzers has a smaller, but still measurable, effect on the total cost. At higher capacity factors, the impact between low ($250/kW) and high ($750/kW) costs is about $0.20/kg. At lower capacity factors, that difference can stretch to around $0.50 to $0.90/kg. These may seem like small differences in price, but when the objective is ultra-cheap hydrogen, a few tens of cents will ultimately make the difference between niche production and global competitive scale-up.

2.10 Hydrogen Production Costs of Different Energy Technologies

The figures above illustrate the relationships between the different factors in terms of overall hydrogen production costs. So how do these map onto the existing portfolio of energy technologies that are available today? It is important to see these as a range because the capacity factors of different renewable energy technologies depend on their location.

Figure 7. **Current hydrogen production costs of different energy technologies**

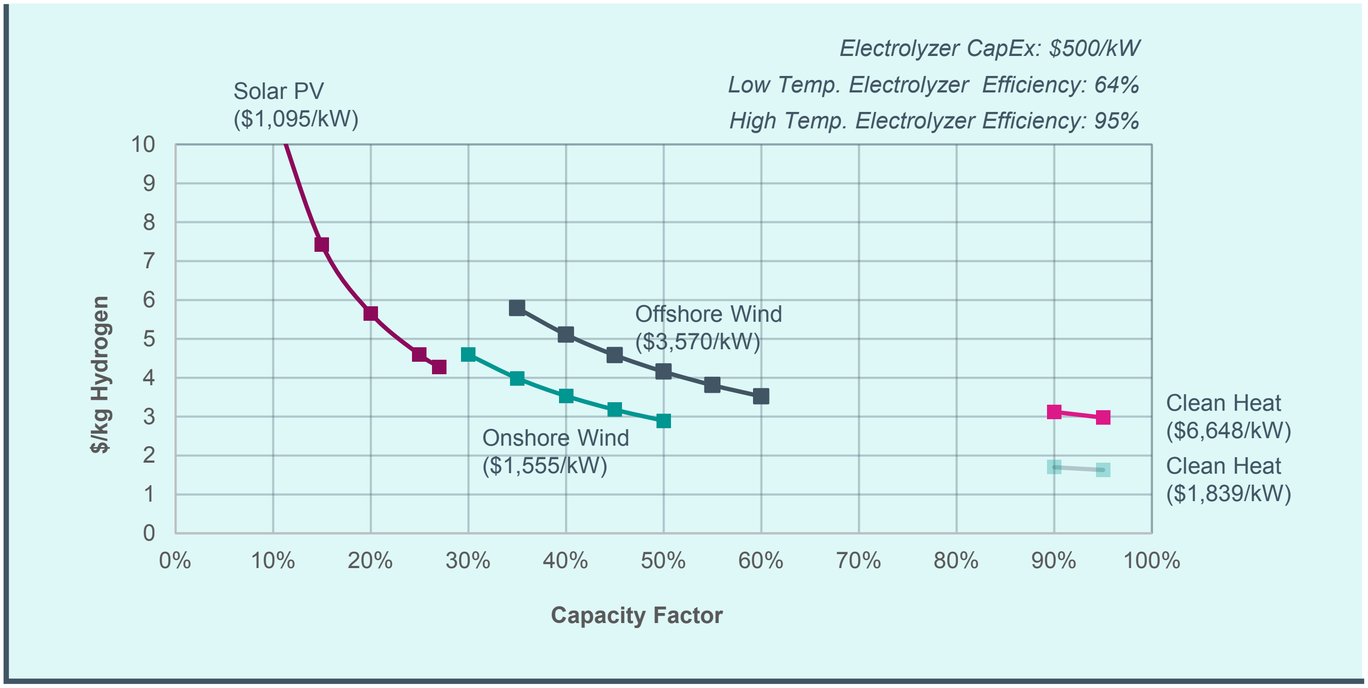


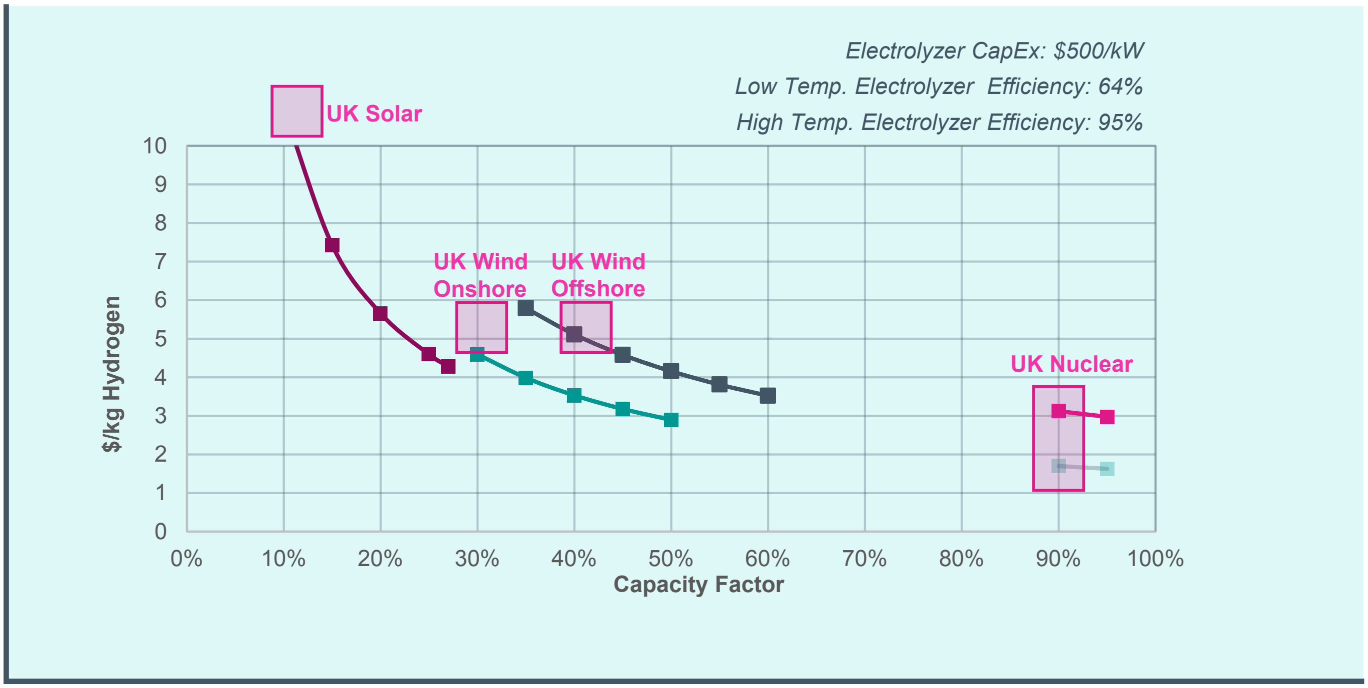
Figure 7 above shows **solar PV** at a CapEx of $1,095/kW with a maximum capacity factor (CF) of 27%, implying a near-optimal location in a hot desert. Even with low-cost electrolyzers (CapEx $500/kW) and a 64% efficiency (low-temperature electrolysis), the best achievable cost for hydrogen production from solar is $4.28/kg.[28] If the quality of the location is lower (e.g., a country like Germany or the UK, where the capacity factor is 10–15%), the production cost increases steeply.

Figure 7 also adds **onshore wind** at an installed cost of $1,555/kW and capacity factor range of 30% to 50%. (This cost is also from the National Renewable Energy Laboratory, using the 2019 'mid'-case for utility-scale onshore wind.) The lowest achievable cost for onshore wind-derived hydrogen is just below $3/kg (also assuming a 64% electrolyzer efficiency). In less optimal conditions (lower CF of 35% or less), cost climbs above $4/kg. **Offshore wind** achieves higher capacity factors but also has higher CapEx, so the lowest achievable cost is $3.50/kg for hydrogen.[29]

Also, on Figure 7, we show **clean heat**-derived hydrogen, using two different 2019 capital costs for high temperature electrolysis. High-cost conventional new-build, such as in the EU or US, cannot produce hydrogen for less than $4/kg even with its higher capacity factor. Lower-cost new-build, such as in China or other Asian markets, can produce hydrogen closer to $2/kg, likely the cheapest near-term option from all the different technologies.

However, all these options are too expensive at current prices to make a dent in global carbon emissions through hydrogen substitution. This is particularly the case in the UK context, as illustrated in Figure 8 on the next page. Solar PV-generated hydrogen is a particularly poor choice economically in the UK due to very low capacity factors in a relatively high-latitude, cloudy country.

Figure 8. **Current hydrogen production costs of different energy technologies in the UK**



2.11 Target Price for Clean Hydrogen

What target price for clean hydrogen would make it competitive with fossil fuels to begin the transition to the hydrogen economy? This price is something of a moving target because it depends first and foremost on the price of crude oil. With a **relatively high oil price**, we calculate that a benchmark of **hydrogen priced at $1.50/kg** as a feedstock for ammonia should be sufficient to begin and maintain the transition towards hydrogen-based alternative liquid fuels.

A cost of $1.50 for hydrogen would yield ammonia competitive with a finished fuel product price (not crude oil on commodity markets) of $15/GJ or $90/bbl. Assuming a refining mark-up of about $15–20/bbl this is equivalent to a $70–75/bbl crude oil price. If crude were at a much lower price of $30/bbl, assuming the same refining margin, this would equate to a refined product selling at $45–50/bbl, or $7.50–8.25/GJ. At this finished product price, direct use of hydrogen would be competitive at $1–1.15 and as a feedstock for ammonia, at a lower $0.90/kg.

Thus **$0.90/kg hydrogen** can be seen as a benchmark for competitiveness in an era of **cheap oil**, while $1.50/kg hydrogen would suffice in case of more expensive crude oil. **These prices represent the crude oil price 'guardrails' of the hydrogen economy**, as shown in Figure 9 on the next page. However, as oil becomes less useful in the economy due to climate mitigation measures its price is likely to fall due to over-supply. It is therefore a risky bet to assume that the heavy lifting for the hydrogen transition will be assisted by high oil prices under normal market conditions.

We therefore see $0.90/kg hydrogen as a more reliable target for ultra-cheap hydrogen that will likely allow the substitution for hydrocarbon liquid fuels to accelerate in future decades, and without being dependent on political moves such as a high, sustained carbon price. Note however that hydrogen costs would need to be as low as $0.50/kg to compete with crude oil prices of $10–15 per barrel.

Previous hype cycles heralding the dawn of the hydrogen economy, first in the 1970s and then again in the 2000s, have fallen short of hopes because the price of hydrogen was much higher than would be needed to drive a transition away from fossil fuels. For this time to be different, $0.90 hydrogen is required—not in 2050, but now.

Figure 9. **Oil price ‘guardrails’ of the hydrogen economy ($0.50–1.50/kg hydrogen)**

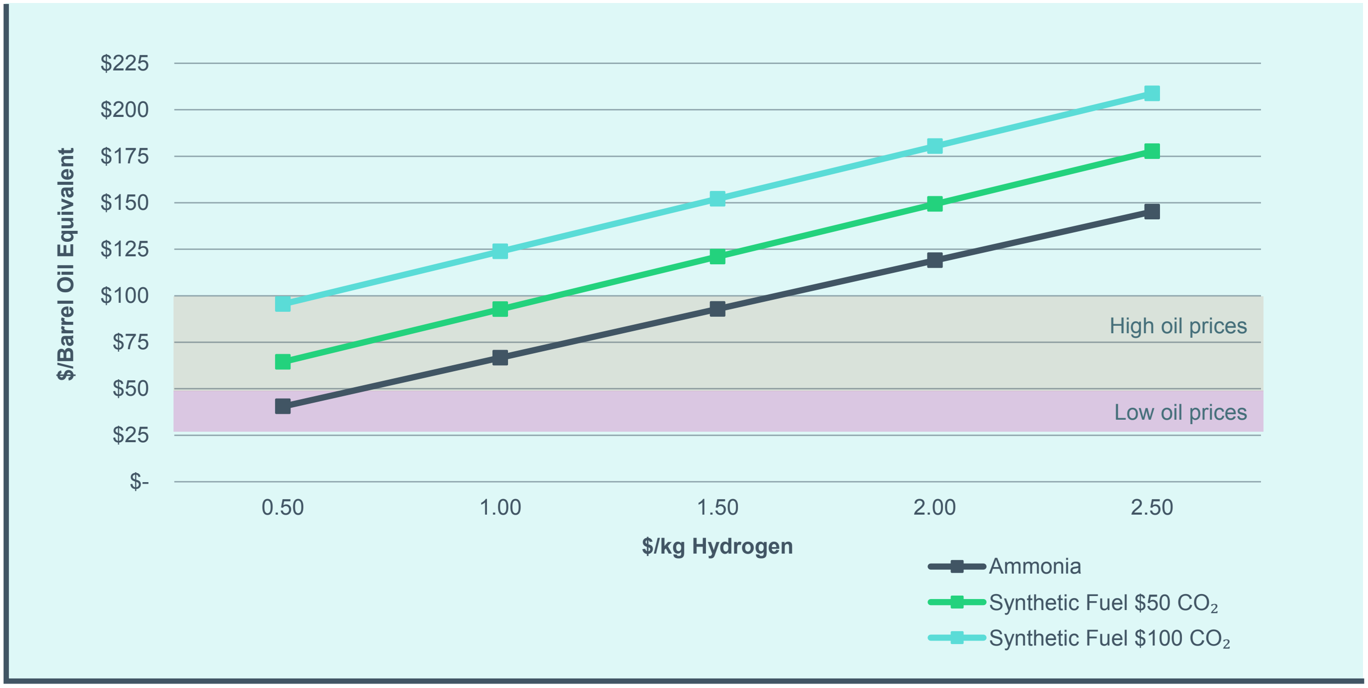


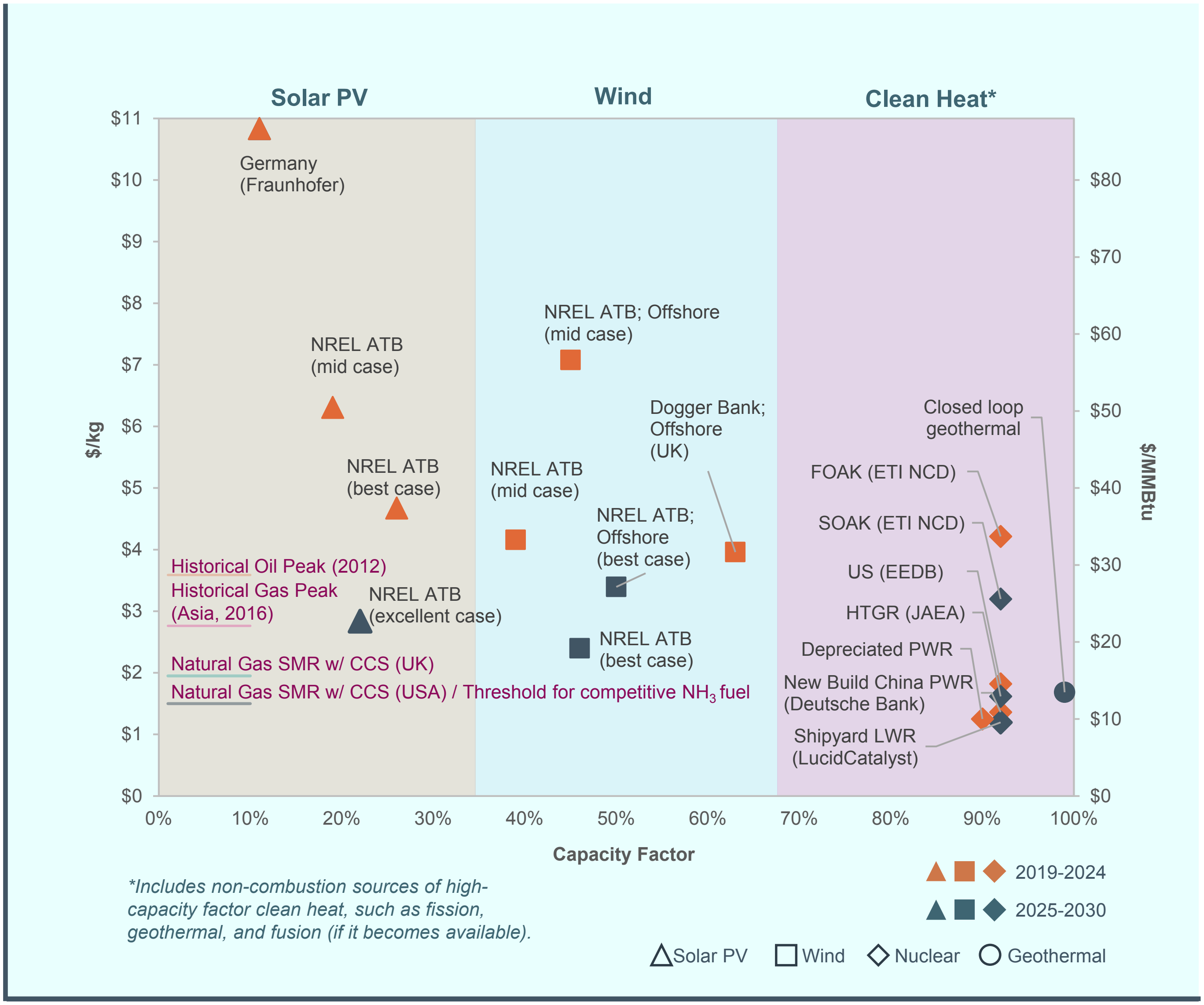
Figure 9 above shows the cost behavior of synthetic fuels manufacturing. The graphic depicts product cost as a function of hydrogen cost. The analysis shows hydrogen prices from $0.50/kg to $2.50/kg.

Synthetic fuels can compete with oil, particularly as the cost of hydrogen drops. Figure 9 depicts two categorically different synthetic fuel pathways that are both competitive with fossil fuel. Categorically, the two pathways are a hydrocarbon pathway and an ammonia pathway.[30,31] Both are attractive synthetic fuels. Figure 9 highlights how ammonia economics and synthetic hydrocarbon economics differ. Significantly, notice that there are two lines for synthetic fuel and only one for ammonia. Because synthetic hydrocarbon production requires a source of carbon, two lines show two different CO_2 costs: $50/tonne and $100/tonne. Regardless of the source of carbon or carbon dioxide, the key take-away is that there is a feedstock price to account for, and a market for CO_2.

As shown in Figure 10, parts of the world are already delivering conventional heat sources cheaply enough to make hydrogen (based on high-temperature electrolysis with a depreciated pressurized water reactor whose CapEx has long ago been recouped) for close to $1/kg. Industrial capability in these countries, such as China and Korea, is advanced and experienced in scaling up chemical plants. Assuming that sufficient grid electricity would still be produced from other carbon-free sources, these countries could open up large export markets for hydrogen-based clean fuels in the near future from existing power plants. However, hydrogen from wind and solar remains at or above $3/kg at the current time.

Looking forward to 2030 and using cost projections from the National Renewable Energy Laboratory, best-case wind and solar will be able to produce hydrogen at $2–3/kg in a decade, a significant improvement but still too expensive to compete with ‘grey’ hydrogen in the absence of a high price on emitted carbon and/or carbon capture and sequestration (CCS). Only clean heat-derived hydrogen is expected to be able to achieve close to price parity with fossil fuels, with best-case modular-built advanced modular reactors at or below $1/kg (this scenario is outlined further below.)

Figure 10. **Cost of hydrogen production from different energy technologies in the real world now and in 2030**



Sources: Unless otherwise indicated, capital and operating costs and capacity factors for solar and wind were sourced from the National Renewable Energy Laboratory's Annual Technology Baseline (NREL ATB). Nuclear costs and capacity factors were sourced from "The ETI Nuclear Cost Drivers Project: Full Technical Report," (by LucidCatalyst) September 2020 as well as the NREL ATB. Sources for the range in electrolyzer costs included publications from McKinsey, Bloomberg New Energy Finance, the IEA, NREL, and Idaho National Laboratory. For more detail on sources and assumptions, please refer to Appendix A.

Forecasting the future prices of energy assets is necessarily an imprecise art, and many previous projections of renewables prices (especially solar) have proven unduly pessimistic. The numbers in Figure 10 on the previous page do, however, represent the current consensus of energy forecasters.

While solar in the UK will never be a viable option for cheap hydrogen due to low capacity factors, we are enthusiastic about efforts currently underway to explore scaling up solar PV in hot deserts, where the 'stranded asset' of intense sunshine far from electricity markets might make hydrogen production an attractive option for large industrial facilities. This might particularly be the case for Gulf states needing to transition away from economic dependence on oil, and already plugged in to supplying world energy markets as their economic export model. Several oil dependent countries in the Middle East have large areas of sparsely populated desert with nearby coastlines (as a source of desalinated water) and enjoy high solar resource for most of the year. In these areas the very large land takes implied by multi-gigawatt solar PV installations might be delivered at relatively low ecological cost and be politically acceptable because there are few competing uses of desert land. If ultra-cheap solar can produce ultra-cheap hydrogen this source can be expected to enjoy rapid growth and play a significant role in the transition.

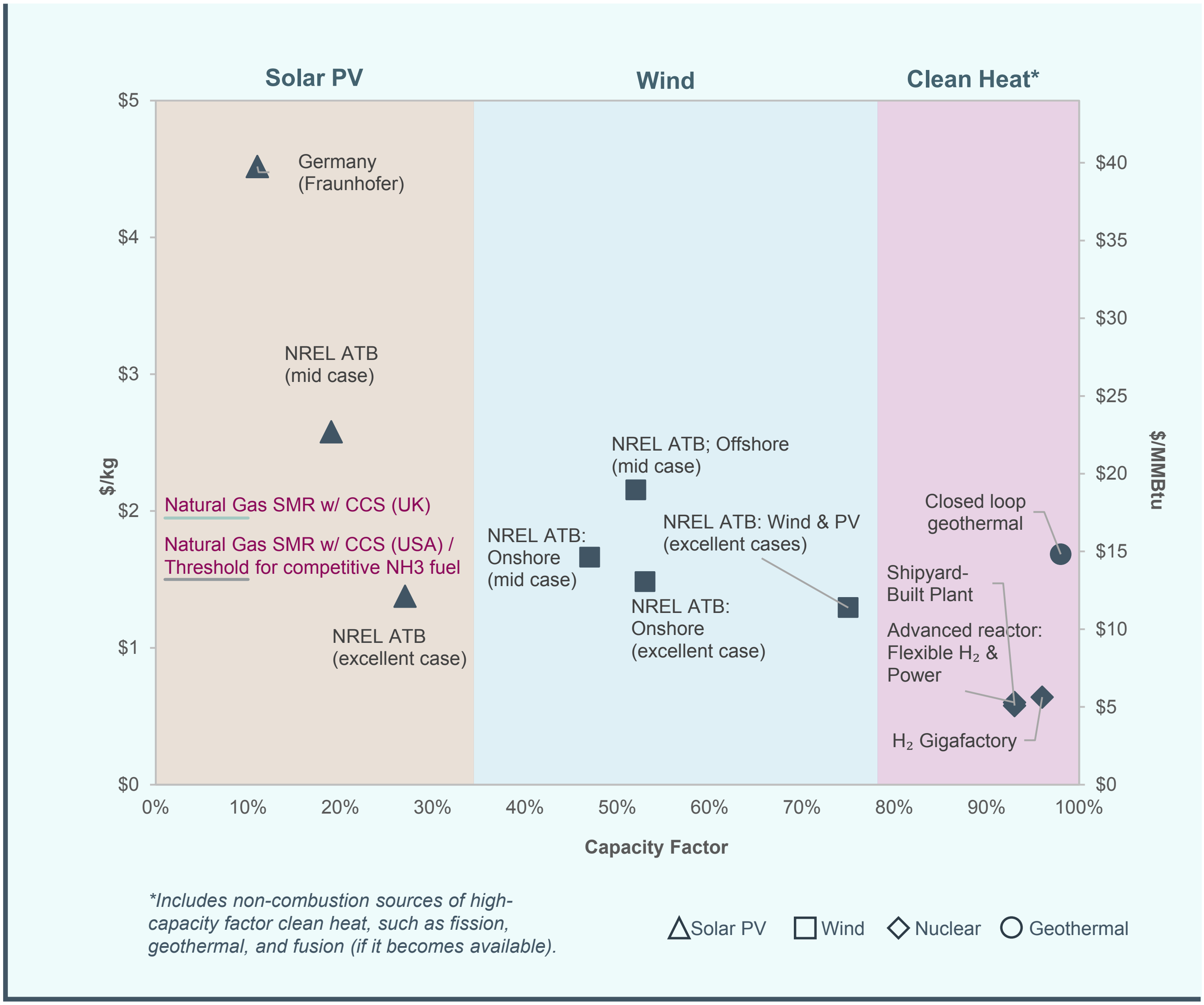
In our view, the climate mitigation discourse needs to move away from 'all or nothing' ideologically motivated approaches: in reality the least-cost, least-risk pathway is likely to be one incorporating many diverse energy technologies. However, the scale required—tens to hundreds of thousands of square kilometers of solar PV, and even larger areas for offshore wind—mean that renewables on their own cannot quickly replace even a fraction of markets for liquid fuels due to physical (material flows and land constraints) as well as cost constraints on the timescales required. Pathways which contain a significant—and in our view, majority—contribution from clean advanced heat sources for hydrogen generation will be cheaper, quicker, and have lower ecological cost and less political risk.

We find that a new generation of advanced modular reactors, hereafter referred to as *advanced heat sources*, with new manufacturing-based delivery models, could deliver hydrogen on a large scale for $1.10/kg, with further cost reductions at scale reaching the target price of $0.90/kg by 2030. For the near term, we are referring to advanced modular reactors, but in the longer term, *advanced heat sources* could also include fusion and high-temperature geothermal. These additional advanced heat sources could be designed as drop-in modules to the production platform architecture described in this report.

As Figure 11 on the next page shows, by 2050 we expect high-volume manufactured, high temperature, advanced heat sources to be the cheapest of all available options, because even with the best wind and desert PV, most renewables are still above our target price of $0.90/kg hydrogen. These projected cost figures for renewables originate from NREL, and closely match the separate projections of BNEF, which projected that with strong policy support and a high carbon price hydrogen costs in the world's best renewable resources, might fall to $0.70–1.60/kg by 2050.[32] Thus renewable-derived hydrogen might reach cost parity with fossil fuels in thirty years—much too late given the warming impact of the cumulative emissions that will take place between now and then. To get back to 1.5 to 2°C pathways, the transition to net zero carbon emissions has to start now and be fully complete by 2050, not start in 2050.

Perhaps the smartest approach would be for advanced heat sources to do the 'heavy lifting' for the hydrogen economy by addressing difficult to decarbonize areas while renewables are more straightforwardly directed towards the task of rapidly decarbonizing electricity supplies. Our proposals for how this might work is the focus of rest of this report. In our view, given the technologies available today, **only with a major contribution from clean, low-cost hydrogen can net zero carbon emissions be achieved in time to avoid climate breakdown.**

Figure 11. **Projected cost of hydrogen production from different energy technologies in 2050**



Sources: Unless otherwise indicated, capital and operating costs and capacity factors for solar and wind were sourced from the National Renewable Energy Laboratory's Annual Technology Baseline (NREL ATB). Nuclear costs and capacity factors were sourced from "The ETI Nuclear Cost Drivers Project: Full Technical Report," (by LucidCatalyst) September 2020 as well as the NREL ATB. Sources for the range in electrolyzer costs included publications from McKinsey, Bloomberg New Energy Finance, the IEA, NREL, and Idaho National Laboratory. For more detail on sources and assumptions, please refer to Appendix A.

2.12 Costs of Clean Heat-Derived Hydrogen

The evidence presented above suggests that clean heat-derived hydrogen could be produced at a large scale, and cost competitively, compared to other clean production methods. Costs must come down further, however, for these aspirations to be realistic. To enable low-cost, large-scale hydrogen production, the delivery model for advanced heat sources must be radically transformed to lower the CapEx (delivered heat and/or electricity) to below $1,800/kWe, and operating costs in Europe and North America need to be reduced by more than 60% (See Figure 7 on page 19). Furthermore, there needs to be much less financial risk associated with delivery of construction projects.[33] This means building projects faster, at lower cost, with simpler and more streamlined operations. There is no fundamental obstacle to achieving this with new models of manufacturing, delivery, licensing, and operations. To be clear, this is a radical departure from the traditional construction model. As we saw above, the physics is favorable: now we need to focus on transforming the delivery model.

As indicated in Figure 10 on page 22, the lowest potential cost of hydrogen by 2030 is achieved by moving to a fully manufactured approach in either a shipyard or factory setting. We describe precise models for how this might work below. Beyond 2030, we foresee that innovative delivery and deployment models combined with next-generation high temperature advanced heat sources can drive costs low enough within the time frame necessary to achieve complete decarbonization by 2050. We will outline decarbonization pathways later in this report.

2.13 Electrolyzer Costs and Performance Assumptions

Table 2 below includes the electrolyzer assumptions for the cost of hydrogen figures earlier in this section.

Table 2. **Electrolyzer costs and performance assumptions**

	2019	2030	2050
Low Temperature Electrolyzer Efficiency (LHV)	64% (a)	69% (a)	74% (a)
High Temperature Electrolyzer Efficiency (LHV)	95% (b)	95% (b)	95% (b)
Electrolyzer CapEx ($/kW)	$750 (c)	$400 (d)	$250 (c)

Sources:

(a) IEA (2019). The Future of Hydrogen. Assumptions Annex. Page 3.

(b) Idaho National Laboratory (2019). Evaluation of Non-electric Market Options for a Light-water Reactor in the Midwest. August 2019. US DOE, Office of Nuclear Energy.

(c) Hydrogen Council (2020). Path to hydrogen competitiveness: A cost perspective. Jan. 20, 2020. Exhibit 14.

(d) This number is our interpolation. IEA's "Future of Hydrogen" assumes $700/kW, and Bloomberg NEF assumes $135/kW in 2030. We treat both of these figures as outliers and use the average. This closely aligns with McKinsey's forecast for electrolyzer costs assuming fairly significant deployment between today and 2030.

3

Next-Generation Advanced Heat Sources for Hydrogen Production

Clean hydrogen will remain a niche product unless costs can come down to our benchmark target of $0.90/kg. For renewables, this fall in prices is not expected to happen much before mid-century if at all. At today's high prices, traditional heat sources cannot compete either. To achieve the transition in the timescales necessary to stabilize the climate, we must transform every step of the deployment process. Achieving low-cost hydrogen will require a new generation of advanced heat sources, which we describe next.

3.1 Low-Cost Hydrogen from Advanced Heat Sources

Advanced modular reactors are hereafter referred to as *advanced heat sources*. In the longer term, this category of advanced heat sources could also include fusion and high-temperature geothermal, but for the purposes of this report advanced heat sources are referring to advanced modular reactors.

Steep near-term cost reductions are only achievable by shifting from traditional 'stick-built' on-site construction projects to factory-style, modular, high productivity manufacturing environments. Next, we present two designs: (1) the Gigafactory, and (2) the shipyard-manufactured production platform, based on the floating production, storage, and offloading facilities (FPSOs) of today's very large oil and gas industry vessels.

Moving from traditional construction to highly productive shipyard manufacturing will dramatically lower the cost of clean hydrogen and synthetic fuels production. Existing shipyard production already has extensive capacity to deliver designed-for-purpose hydrogen production facilities and could be both upgraded and expanded to meet increased demand, as detailed below.

Both designs offer potential pathways for delivering the necessary hardware at the required global scale. From the energy industry's point of view, this represents a radical departure from today's industrial, business, and technology model of 'build-at-site, one-plant-at-a-time approach,' with very little advanced manufacturing and design standardization. However, the business model proposed—large, centralized, efficiently delivered and managed, for global markets—is not new and has been widely demonstrated in other sectors. For example, this is precisely how the oil and gas industry currently operates.

3.2 The Gigafactory

The Gigafactory is a highly productive, dedicated manufacturing facility where the high-temperature heat sources, and associated equipment, are fabricated and installed on site. Hydrogen production facilities are also manufactured, installed, commissioned, and operated on site. The Gigafactory produces hydrogen, which can be fed directly into existing national gas infrastructure or used for other applications such as conversion to ammonia.

The multiple advanced heat sources are small modular 600 MWt (Megawatt-thermal) units with a complementary heat exchanger unit that transfers the heat to the molten salt heat supply network for a thermochemical hydrogen plant. Manufacturing facilities would be built with rail and port access, allowing the manufacturing plant to 'export' high-value components that are not necessarily used at the facility when the construction of the plant is complete.

Hydrogen Gigafactories like this can be sited on refinery-scale brownfield sites, such as large existing coastal oil and gas refineries, with large-scale interconnection points to the gas grid. This avoids the need to interconnect multiple scattered hydrogen projects to the main gas grid. It may also be favorable to co-locate ammonia production facilities or other synthetic fuels conversion plants using hydrogen as a feedstock, which benefit from low-cost electricity and hydrogen.

Figure 12. **Rendering of a hydrogen Gigafactory under construction**

Artwork by Simon Clements

The Gigafactory brings clean power plant project delivery into the 21st century. The entire facility is carefully designed for manufacturing and assembly, enabling a highly productive automated factory-based production system for the fabrication, assembly, and installation process. These simplified lean designs (with fewer components) minimize labor costs and enable the application of fast, high-quality modular construction techniques.

The high-quality, standardized process provides an exemplary environment for regulatory oversight. Because the regulator sees the same factory, same team, same processes, operating continuously—approvals can be streamlined, and regulatory costs should fall over time. With factories onsite making advanced heat source components and power conversion sets in parallel, construction delays are minor and do not accumulate during the construction process.

The vertically integrated site enables significant economies of scale from building multiple uniform units, and site mobilization costs (along with other one-time costs, such as safety-grade component documentation) are spread across dozens of units. Finally, vertical integration also eliminates major component transportation costs, transportation related delays, and reduces inspection costs. As the project nears completion, advanced heat source units can be exported to additional projects offsite via rail or ship.

The onshore Gigafactory can put hydrogen directly into the gas grid, helping to decarbonize existing domestic gas use for consumers, or stored. Storage facilities, such as salt caverns, ensure adequate reserves to make deliveries at times of peak demand.

Figure 13. **Another view of a hydrogen Gigafactory under construction**

Artwork by Simon Clements © LucidCatalyst

The buildings on the far left include the advanced heat source manufacturing/assembly facility (larger building) and precast facility (smaller building). On the left is the reactor manufacturing facility. In the middle, operational reactors (blue hatches) reside below-grade next to their accompanying heat exchanger 'pods' (green hatches). The hydrogen production facilities are on the far right.

Hydrogen produced in this configuration is within national borders and need not be subject to geopolitical risk attached to dependence on overseas fuel supplies, strengthening national energy security. Salt cavern storage of hydrogen, which is extremely low cost, would ultimately allow flat production to match the huge seasonal swings in northern heating markets in Europe and North America. For example, in the UK, the energy supplied via the natural gas network over a typical year, the majority of which goes for heating, is twice that carried by the electric grid.

To provide an example at scale: A Gigafactory of 36 small reactors with 600 MWt high temperature capacity each would have a total capacity of 21.6 GW thermal. If roughly 45% of that thermal energy is turned into hydrogen, that is ~76,632 GWh H_2 per year (assuming a ~90% capacity factor). Approximately 10 of these Gigafactories would be needed to supply the 700 TWH in the UK Committee on Climate Change's Net Zero scenario.[34] Sufficient industrial brownfield sites, such as disused refineries, already exist in the UK to accommodate facilities at this scale with no need for greenfield sites. These Gigafactories would also provide many well-paid jobs. Local governments would likely to compete to be the locations for such substantial inward investment.

3.3 Shipyard-Manufactured Offshore Energy Platforms

Since the 1970s, shipyards have evolved into some of the most productive manufacturing environments across all industries—particularly when it comes to large-scale fabrication. Decades of fierce competition and a large and growing demand for ships, offshore platforms and offshore production facilities have fostered world-class design capabilities, manufacturing, and quality assurance programs in the world's leading commercial shipyards. The goals of the shipyards and their owners are ideally matched to the need for manufacturing high-quality, cost-competitive production platforms on schedule, and in high volumes.

These high-tech, large-scale shipyards are well suited for fabricating synthetic fuel production platforms. Some studies have already concluded that the scale of the manufacturing infrastructure at shipyards means that it is possible today to build an entire power plant in a shipyard and float the finished product to its final location. The final location may be onshore at a coastal site or offshore.

Learning from Offshore Wind

The offshore wind industry has smashed expectations with increasingly low prices: £39.50 (~£46.50 in 2019 GBP) per MWh for UK new-build commissioned by 2025. This represents a halving of costs achieved in a five-year period, illustrating the power of innovation, collaboration, and drive. By identifying and demonstrating cost reduction across key areas including foundations, high voltage cables, electrical systems, access in high seas and wind measurement, the sector has transformed its overall performance on cost and delivery.

In order to meet the target UK fleet size (30 GW by 2035), offshore wind deployment must increase significantly from current levels: turbines will have to be installed at a rate of two per day, whilst moving towards higher power density.

A key feature of the offshore wind sector transformation was a transition to modular build and factory-based assembly of mass-produced units that can be manufactured and shipped to sites for installation rather than custom-built, thereby speeding up delivery times and lowering direct and financing costs. Technological innovation has been coupled with a laser-like focus on accelerating commercialization of new products, at scale, within rapid timescales.

The main advantage of shipyard manufacturing comes from high productivity, which leads to lower costs and faster projects. Shipyard productivity is among the highest in the world. Labor costs constitute only 10–15% of the final assembly and delivery cost. By contrast, labor constitutes up to 35% of the costs in best-in-class conventional construction. The most productive shipyards in Korea and Japan have been able to sustain 10–15% per year improvements in productivity over multiple years.

This productivity is made possible through, for example, innovation: shipyards are leading innovators in design and build processes, having adopted the most advanced 3D design and simulation tools, as well as implementation of advanced cost-reduction technologies such as robotics/automation in fabrication and inspection.

Shipyards can also make best use of skilled labor. Unlike construction workers, who are temporarily onsite for any given project, the workers at a shipyard are often local residents, and view working at the shipyard as their long-term career. This provides strong alignment for deep development of skills and a culture of quality that is built around the production processes executed every day. The largest shipyards employ 25,000 or more personnel, with extensive cross training and skill sets.

Shipyards invest extensively in supplies, tools, support systems, and transportation systems. Together these investments provide for an extremely efficient and productive work environment compared with even the most efficiently organized construction site. They also develop, maintain, and follow strict quality control and quality assurance programs not unlike the nuclear and aerospace industries. These programs must satisfy national and international standards to ensure safe transport of volatile commodities such as liquefied natural gas and other chemicals. They have tight tracking of parts and status, with barcodes and/or Radio Frequency Identification (RFID) tags, throughout the facility and the broader supply chain.

The Model: Petronas PFLNG

The production platforms are based on the physical dimensions of the Petronas PFLNG Dua hull (393 meters long, 64 meters wide) as well as the multitude of floating offshore plants that have been designed over the past several decades. The hull, which has a total dry weight of 152,000 metric tons and accommodation for 150 personnel, is large enough for 1.2 GWe of advanced heat sources with power generation systems. These are housed below deck, along with storage for liquid products. All processing equipment sits on deck. The turret and mooring system, which anchor the ship, can be much less expensive and complex than the one used on the Petronas PFLNG, as multiple pipeline connections to subsea gas production equipment are unnecessary for this application. Each production platform may be placed near shore in a dredged harbor or moored offshore.

3.4 Hydrogen and Ammonia Production Platforms

The availability of high-temperature heat (>500°C), allows for additional hydrogen production approaches. Although numerous thermochemical processes have been identified in experiments, none are currently commercially available. Therefore, while this may be an option for future hydrogen production systems, we assume high-temperature electrolysis in the production platforms scenarios discussed below. Our reference high-temperature electrolysis process for hydrogen generation is based on the design from a 2013 engineering study by Dominion Engineering.[35] High temperature electrolysis is now beginning commercial deployment.[36]

A notable characteristic of ammonia production is that the process's energy consumption is primarily electricity. The process uses electric generation of hydrogen from water using electrolysis, and electric extraction of nitrogen from the air using electrically-driven cryogenic air separation units. The major electric consumer is hydrogen production. The air separation unit and the Haber-Bosch synthesis equipment are comparatively minor consumers. For reference, a world-scale plant produces ~3,700 tonnes/day of ammonia and consumes ~670 tonnes/day of hydrogen. In such a plant, 93% of the electricity is consumed by the hydrogen producing electrolyzers.

Once moored at its production location, near a suitable diversity of markets, the production platform will begin production of ammonia, which will be stored as a refrigerated liquid and offloaded on smaller transport bunker for delivery to ships and other users. Figure 14 on the next page depicts a bunker preparing to receive ammonia and highlights the production and processing equipment on deck.

Figure 14. **Rendering of ammonia bunker offloading ammonia from a production platform**

Artwork by Simon Clements © LucidCatalyst

The image is to scale and highlights the size difference between the two ships.

3.5 Production Platform Heat Source

Based on the Petronas PFLNG Dua, the heat source and power generation modules are scaled to a heat supply of 2,600 MWt, which gives an electric generation capacity of 1,164 MWe. This is sufficient to produce 1.2 million tonnes per year, as well as meet all other loads on the platform. Table 3 below lays out the technical specifications for the ammonia production platform in more detail.

Table 3. **Ammonia production platform output and physical specifications**

Ammonia Production Potential	
Thermal capacity (MWt)	2,600
Electric capacity (MWe)	1,164
Annual H_2 production capacity (tonnes)	217,030
Annual NH_3 production capacity (tonnes)	1,203,336
Daily NH_3 production capacity (BOE/day)	12,160
Physical Specifications	
Platform dimensions (same as PFLNG Dua)	L: 393 m W: 64 m
Lifetime (years)	30
Displacement (tonnes)	152,000

3.6 Production Platform Heat Source Costs

While we are technology-neutral on the specific heat source, our costings are based on a recent quoted price for a delivered molten salt reactor currently under consideration by the Government of Indonesia, which can be considered representative of advanced heat source technology under a fully modular, shipyard scenario. These high-temperature reactors—operating at over 700°C as compared to the 330°C of conventional light-water reactors—allow for more efficient electrolysis and are passively safe as a feature of their reactor physics and engineering designs.[37]

The estimated cost for a 1 GW plant, large parts of which have been confirmed by a quote provided by the Korean shipyard company DSME, is about $1 billion. This equates to a capital expenditure of $1,000/kW, and which would produce power at a levelized cost of 2.4 cents/kWh (assuming a ~90% capacity factor). As well as producing ammonia via high-temperature electrolysis, this low-cost electricity can be supplied directly to onshore markets, as explained below.

3.7 Production Platform Cost of Hydrogen

Adjusting the economics for the projected cost calculations above yields a hydrogen cost of $1.11/kg, well within what is competitive for oil substitution at moderate/high oil prices, and within striking distance of the $0.90/kg hydrogen cost we consider the target for large-scale hydrogen substitution, given further cost reductions resulting from large-scale deployment.

3.8 Multi-Product Platforms

Offshore siting of the heat source on a production platform has a number of advantages. No one lives within exclusion zones, land use issues and conflicts can be avoided, and safety concerns are further alleviated as the reactors are surrounded by coolant (i.e., ocean water). The production platform is protected by a floating structure that prevents ships from coming within 500 meters. The heat sources are designed to withstand aircraft impact, tsunamis, and other disasters.

Production platforms can also be redesigned to produce a combination of electricity, ammonia, and desalinated water in varying quantities. This poly-generation production facility is designed to moor offshore from coastal cities in regions such as Africa or South-East Asia, which have large unfulfilled demand for all products. The production platform would send its products to shore via pipelines for ammonia and desalinated water, and an underwater transmission cable for the electricity. The idea is that the production platform would provide multiple valuable products for large established coastal cities without requiring the cities to have to invest in three large separate infrastructure projects that are likely not as centrally located. The production platform cost should be significantly lower than separately building a large fuels refinery, power plant, and desalination plant. The baseload desalination process takes advantage of the continuous supply of waste heat from the production platform.

This production platform model could help power coastal cities (e.g., Lagos, Dubai, Kolkata, Jakarta, etc.) and supply clean drinking water to rapidly growing cities in arid regions, particularly as one of the most severe climate impacts is expected to be drought. This electricity/water source can be expected to be more reliable than hydro in drought-affected zones and could help provide cooling as extreme heatwaves increasingly affect the tropics and sub-tropics. It is possible to design the production platforms such that the power output can be set to variably serve electrical power production or fuels production as necessary making the platforms complementary with solar power.

Figure 15. **Production platform for hydrogen, power, ammonia, and desalination moored near shore**

Artwork by Simon Clements © LucidCatalyst

Not shown are the pipelines and underwater transmission cables sending products to shore. Fish farms and wind turbines are in the background.

Offshore siting also means customers can sign a relatively short-term commitment with the production platform. They do not need to think of the investment as a 100-year commitment, which can be the case with onshore power plants. Instead, production platform customers can sign standard commercial contracts with the option to renew based on 'power purchase agreements' pegged to a defined price of electricity.

With the plant's ability to swing between ammonia production and selling electrical power, the plant's output can be flexible enough to complement renewables (e.g., offshore wind, onshore solar PV) and help developing countries meet their decarbonization and energy access targets with a substantial renewables component. This dramatically reduces the amount of storage that would be required, thereby reducing costs, whilst increasing scale.

3.9 Production Platform Regulatory Issues

Construction, operation, regulation, and insurance norms are well established for large offshore platforms and complex power plants. There are approximately 6,000 offshore oil and gas platforms[38] and 440 reactors[39] operating globally today. These are large established industries with legal, regulatory, and financial infrastructure, supporting billions of dollars of annual investment.

There are also well-established precedents for regulating reactors at sea—both for naval purposes, or for power plant ships, such as the floating power plant in Russia (Akademik Lomonosov), or China General Nuclear's forthcoming floating power plant. International protocols have been in place for more than 65 years, successfully shipping uranium fuel without incident. Lloyd's Register, one of the world's most respected class societies and companies in offshore quality assurance for ships and offshore platforms (including standards compliance, validation, and development), has been working with China General Nuclear (CGN) on developing an international licensing framework for floating reactors. The platforms proposed here would be fueled once in location and would not be moved around whilst in operations. This greatly simplifies the regulatory issues involved.

One further advantage of production platforms is that they need to be licensed and regulated in only one country. So even without globally or regionally harmonized regulation and licensing regimes, these production platforms can deliver clean energy products at massive scale that can then be used in multiple countries. Only a small number of countries need to be ready to build and license production platforms of this kind, but the supply of clean abundant fuels could be utilized anywhere in the world.

There may actually be even greater potential to deploy production platforms in developing countries that do not yet have the mature domestic regulatory capability, skills, or supply chains needed to build, maintain, and operate conventional terrestrial plants. It is also these countries that will drive the vast majority of increased energy demand in the coming decades.

Hydrogen from High Temperature Reactors

The Japan Atomic Energy Agency (JAEA) High Temperature Test Reactor (HTTR) has successfully demonstrated continuous thermochemical hydrogen production at pilot scale with the sulphur-iodine process. Note: as wind and solar do not produce heat, they can only ever use the less efficient low-temperature electrolysis option.

Costing for the 275 MWe and 100 MWe+ commercial designs for high-temperature hydrogen-producing reactors has been developed through production-ready quotations from suppliers who have been involved in the project for over 15 years, first participating in building the 30 MWt HTTR and then participating in the design and cost reduction process for commercial-scale units. These commercial suppliers have designed the required components to enable cost-effective manufacturing in their facilities and the JAEA team has led several rounds of design for cost reduction with these manufacturing partners. Production-ready quotes from suppliers suggest a ~$2,500/kW CAPEX for a 4-unit, 1,100 MWe plant (4 x 275 MWe).

The combination of extensive development and testing, design for manufacturability engagement with suppliers, and review of the designs and operations with the regulator, supports the proposal by the management team at JAEA's HTTR that they could have a commercial prototype built and operational in approximately five years if funding were made available today.

Sources

(1) Yan, Xing L. (2017). HTGR Brayton Cycle, Technology and Operations. MIT Workshop on New Cross-cutting Technologies for Nuclear Power Plants, Cambridge, USA, January 30-31, 2017.
(2) Nishihara, T. et al. (2018). Excellent Feature of Japanese HTGR Technologies. JAEA-Technology vol. 2018).

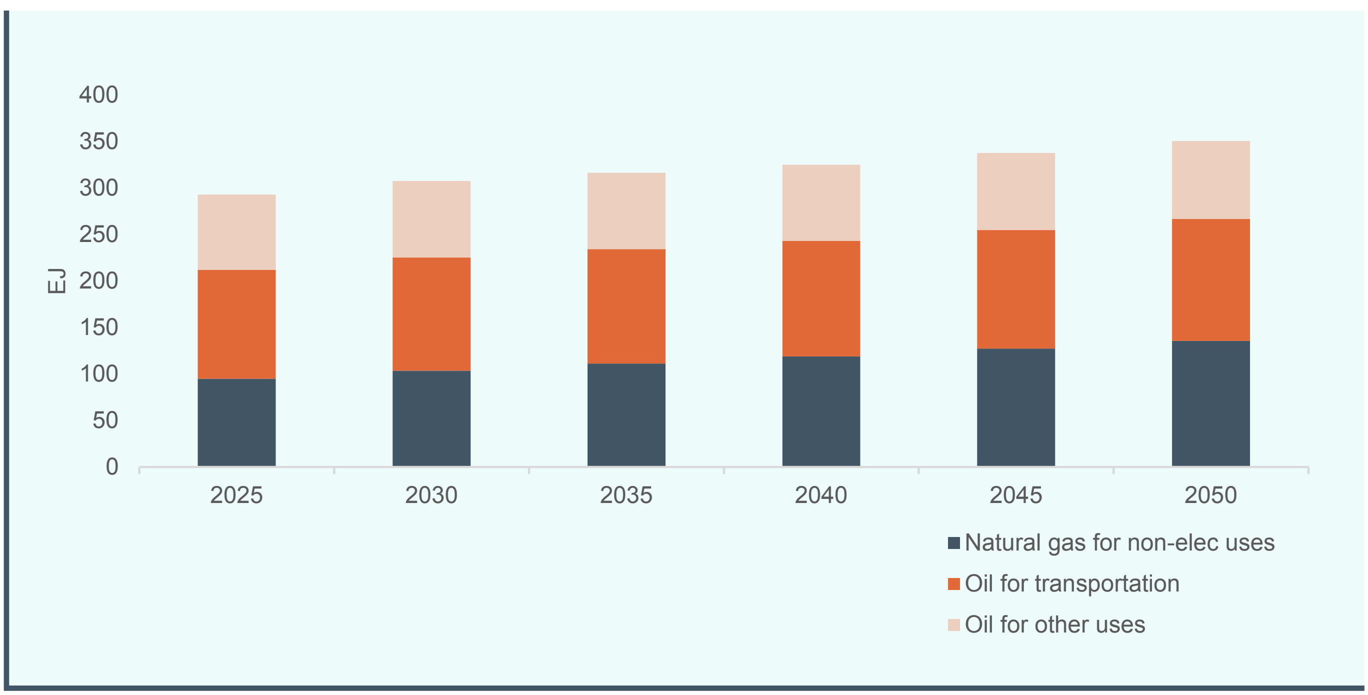
4 The Fuels Decarbonization Challenge

Growth forecasts of the 'difficult-to-decarbonize' sectors of the economy, extrapolated into 2050, predict that these sectors will still be responsible for 17 Gt (gigatonnes) of annual CO_2 emissions.[40] The 17 Gt annual figure is over and above CO_2 emissions from sectors like electricity, which are considered easier to decarbonize and for which it may be reasonable to expect them to be fully carbon-free by mid-century.

Cumulatively, over the period from 2020 to 2050, at an average annual CO_2 emission rate of 17 Gt/year these 'difficult-to-decarbonize' sectors will emit 510 Gt of CO_2 over that 30 years—this emission figure is 100 Gt more than the total remaining carbon budget for the 1.5°C pathway. Given that hundreds more gigatonnes of fossil fuel emissions are still in the pipeline from the electricity sector, this scenario puts 2°C out of reach.

Figure 16 below shows the expected growth in these sectors.

Figure 16. **Projected growth in 'difficult-to-decarbonize' sectors by 2050**



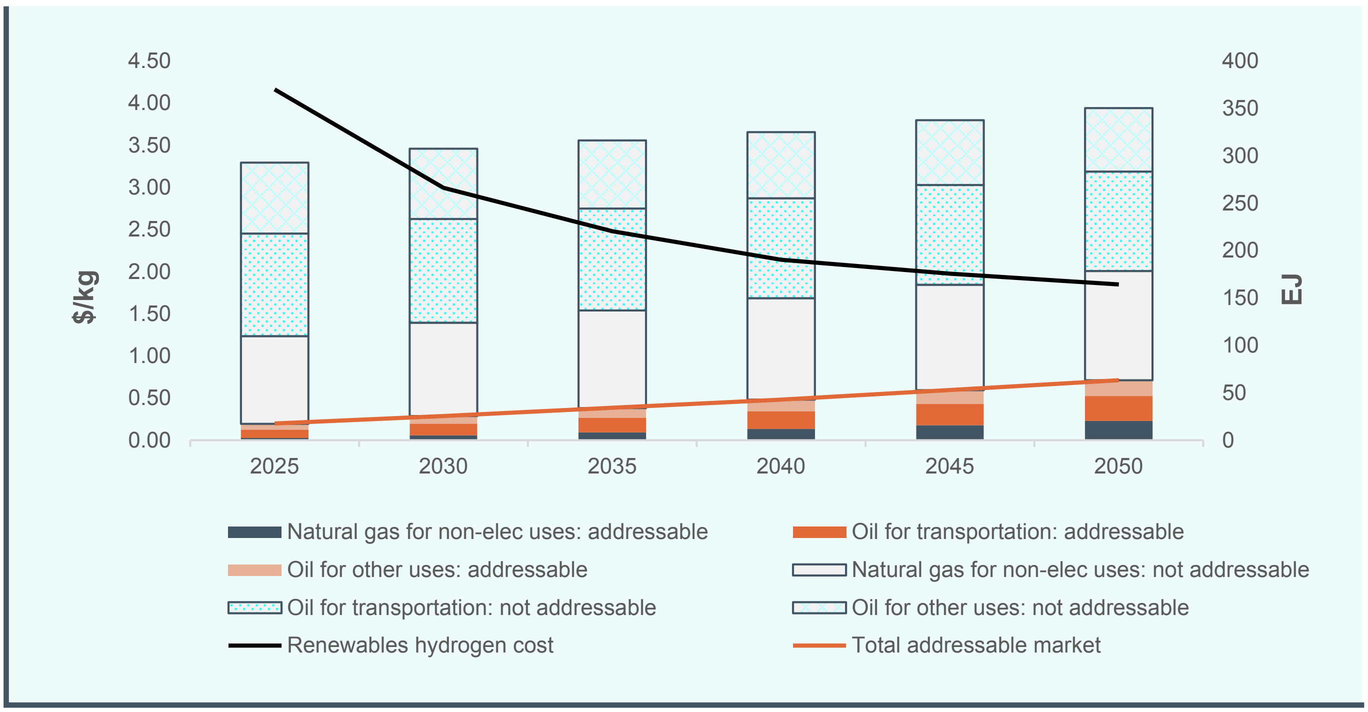
Note: Extrapolated from IEA's "Stated Policies Scenario."

While relatively expensive hydrogen from renewables will gain some market share with strong policy support, as we showed earlier clean hydrogen will remain a niche product unless costs can come down to our benchmark target of $0.90/kg. For renewables this is not expected to happen much before mid-century if at all.

This time lag is demonstrated in Figure 17 below, which shows the increasing market share of relatively expensive renewables-derived hydrogen as production costs fall by 2050. Our figures accord closely with Bloomberg New Energy Finance (BNEF); in its report, BNEF projected green hydrogen supplying 27 EJ of energy to the global economy by 2050 in a 'weak policies' scenario, and 99 EJ energy in a 'strong policies' scenario.[41] Our projections in Figure 17 show a mid-point between the two BNEF scenarios, with green (renewables) hydrogen supplying 63 EJ of 2050 energy.

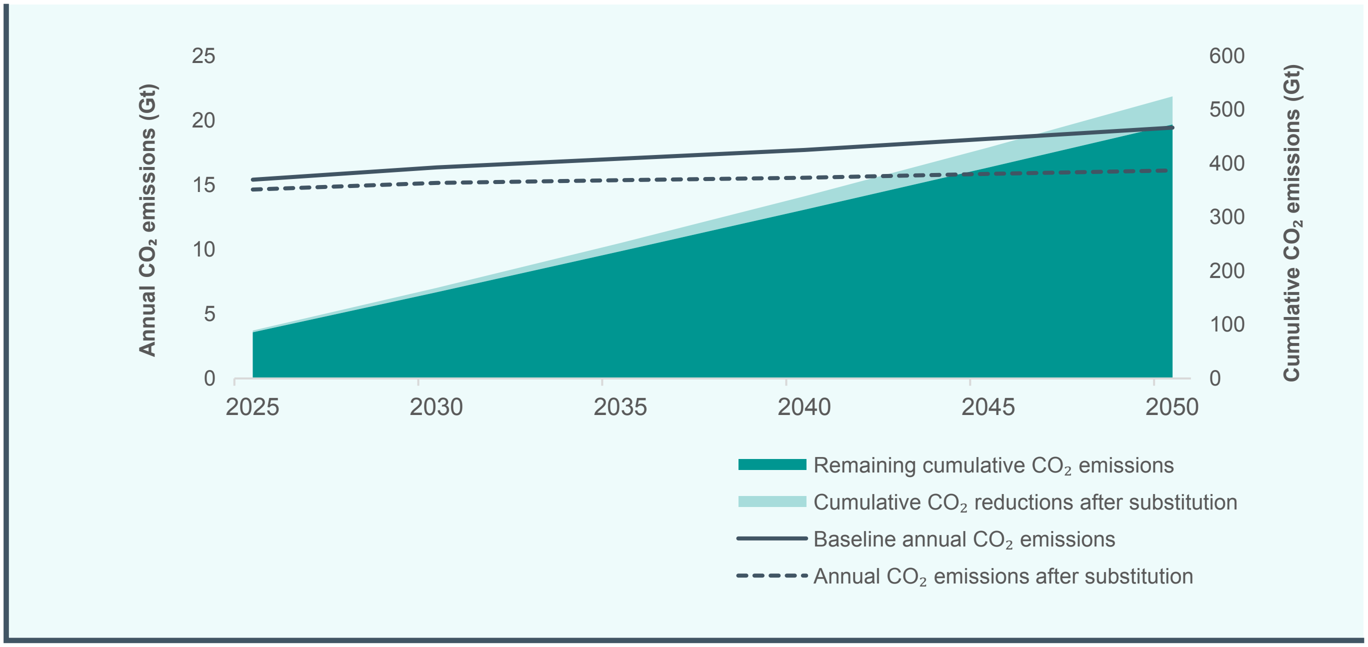
Thus renewable-derived hydrogen might reach cost parity with fossil fuels in thirty years from now—much too late given the warming impact of the cumulative emissions that will take place between now and then. As detailed earlier, to get back to 1.5/2°C pathways, the transition to net zero carbon emissions has to start now and be fully complete by 2050, not start in 2050.

Figure 17. **Sectors of the economy that are 'addressable' with renewables-generated hydrogen to substitute for fossil fuels at different hydrogen production costs over time**



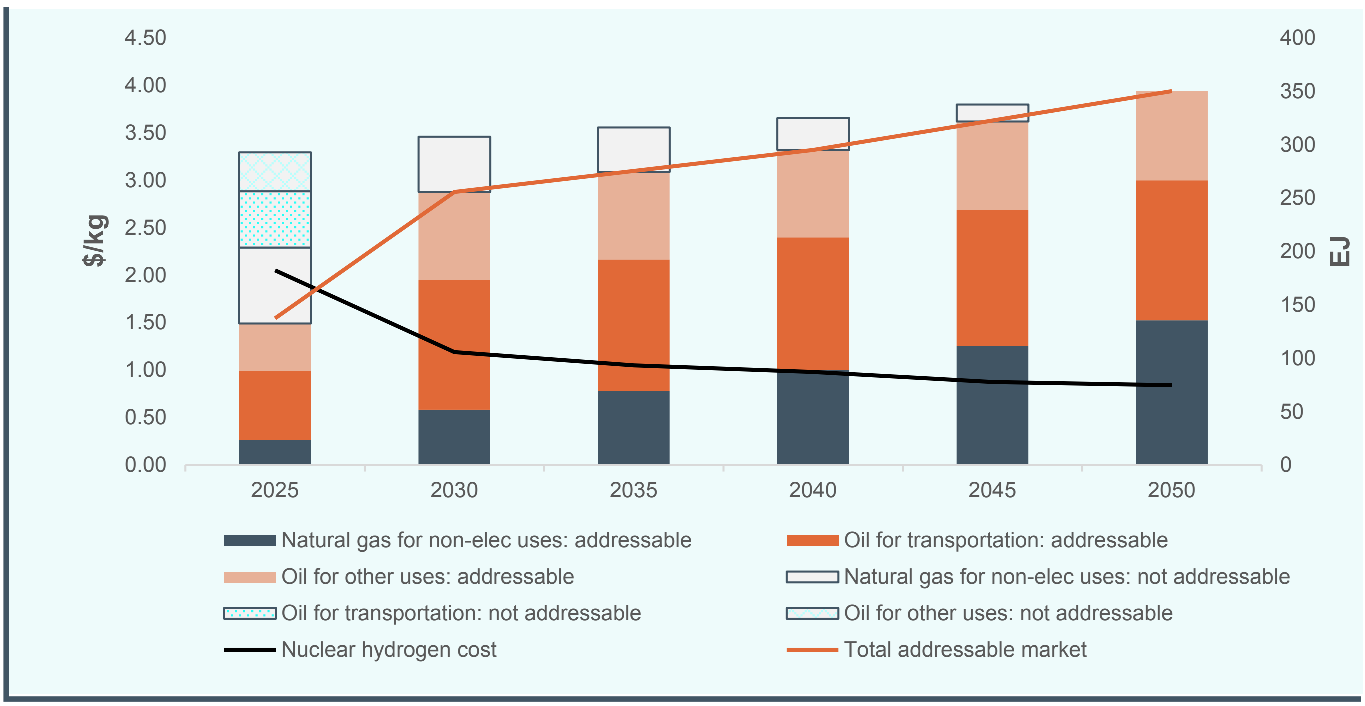
While an increasing number of niche markets can be addressed with 'green' hydrogen from renewables, cumulative emissions by mid-century are still close to 500 Gt, as shown in **Figure 18**. This demonstrates that a renewables-only hydrogen pathway will not be sufficient to put the world on the path to a 1.5/2°C outcome, even assuming that the electricity sector is fully decarbonized by mid-century—itself an enormous undertaking. **The 'missing link to a livable climate' is production of emissions-free, low cost hydrogen to enable global scale and competitive synthetic fuels.**

Figure 18. **Cumulative CO_2 emissions by 2050 showing the reduction achieved by substitution with renewables-only hydrogen as per Figure 17 (Compare with Figure 21)**



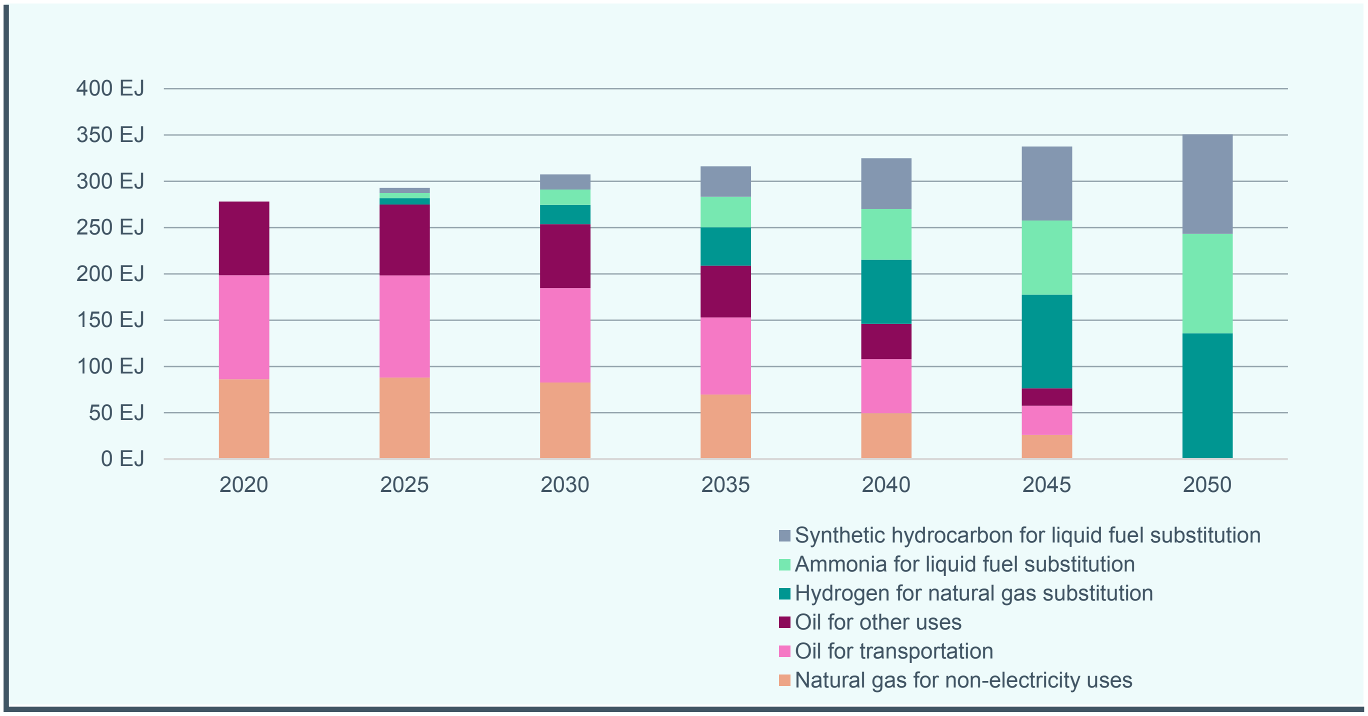
In contrast, **Figure 19** below shows the abatement potential of a scenario where cheaper hydrogen, delivered from advanced heat sources, is able to bring down hydrogen production costs from $2 today to under $0.90 well before 2050. The near-term potential of low-cost hydrogen accelerates timely and deep decarbonization across all the relevant sectors.

Figure 19. **Sectors of the economy that are 'addressable' with clean heat-derived hydrogen to substitute for fossil fuels at different hydrogen production costs over time**



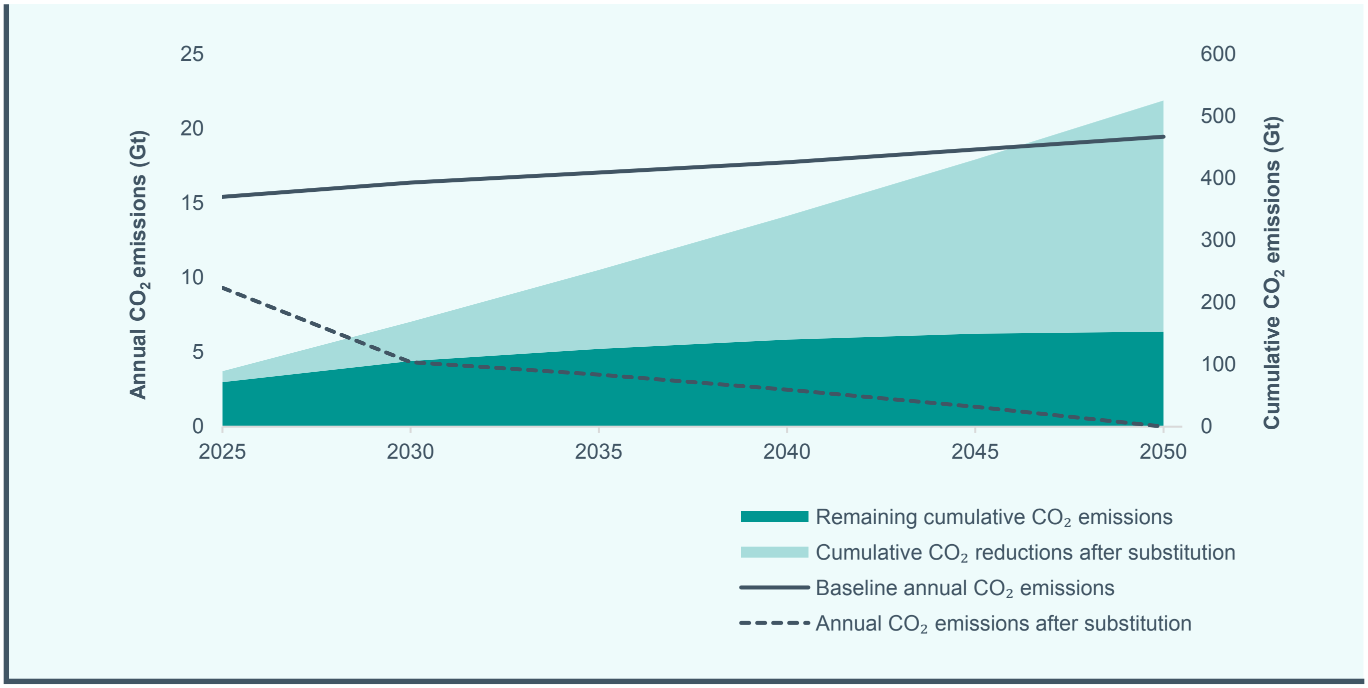
In order to provide more detail on how the fuel substitution takes place between 2020 and 2050, **Figure 20** below details the specific fuels and sectors concerned.

Figure 20. **Fuel substitution in different sectors from ultra-cheap hydrogen generated by advanced heat sources 2020–2050**



This displacement of carbon in the difficult-to-decarbonize sectors brings emissions down to zero by mid-century, keeping cumulative emissions under 150 Gt. Assuming this is accompanied by decarbonization of 'easier' sectors like electricity over the same timescale, this maps out a credible pathway to global net zero carbon emissions by 2050. **Figure 21** on the next page displays this transition, which would put the world on the pathway not just to a 2°C outcome, but a 1.5°C outcome as required by the 2015 Paris Agreement, thanks to the **avoidance of 400 Gt of cumulative CO_2 emissions**. The rate at which the world could achieve these emissions reductions will depend on the extent of the industrial mobilization to deliver these production platforms.

Figure 21. **Net Zero carbon emissions**

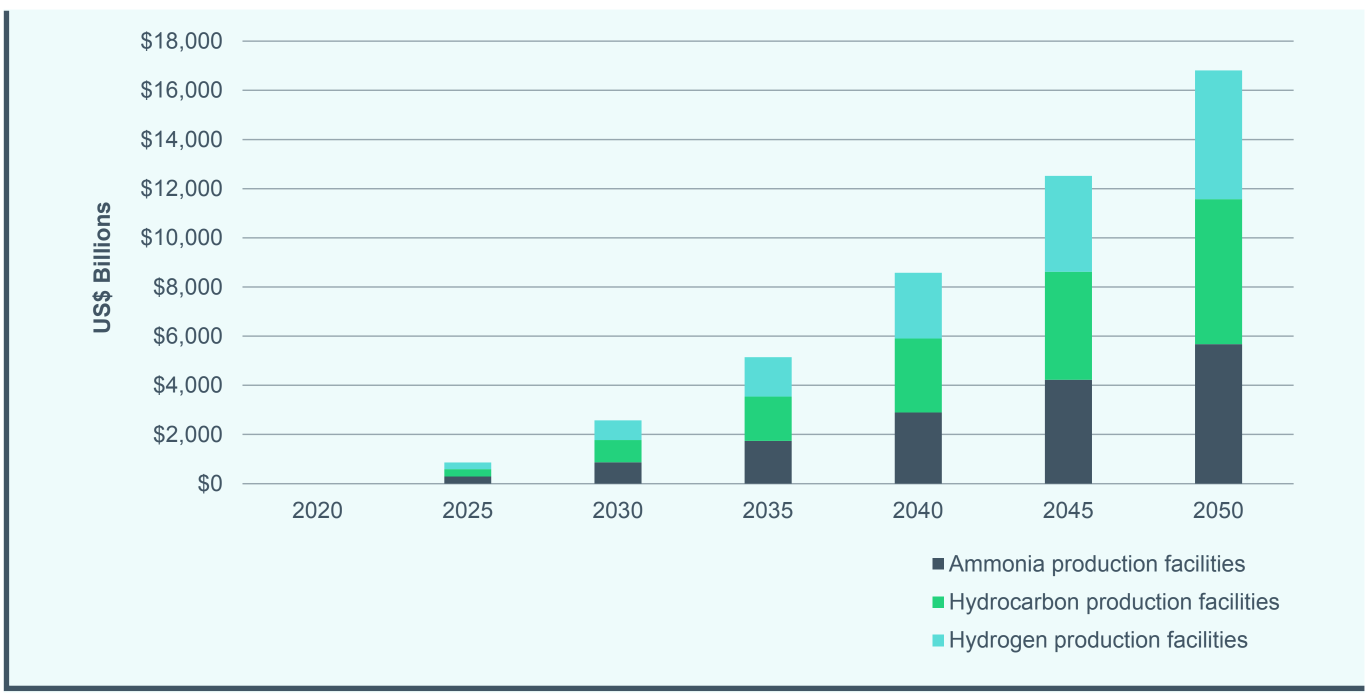


5 Total Investment Requirements

How much would this transition cost? A useful benchmark is the investment that will be required to maintain supplies of fossil fuels over the same time period if hydrocarbons continue to be dominant. Global oil and gas exploration and production (E&P) investment was US$540 billion in 2019. Maintaining existing flows of oil and gas consumption equivalent to approximately 100 million barrels of oil per day is projected to require investments of $16.7 trillion over the period 2020–2040.[42] By extrapolation, another $8.3 trillion can be expected 2040–50, taking the total oil and gas investments by mid-century to $25 trillion.

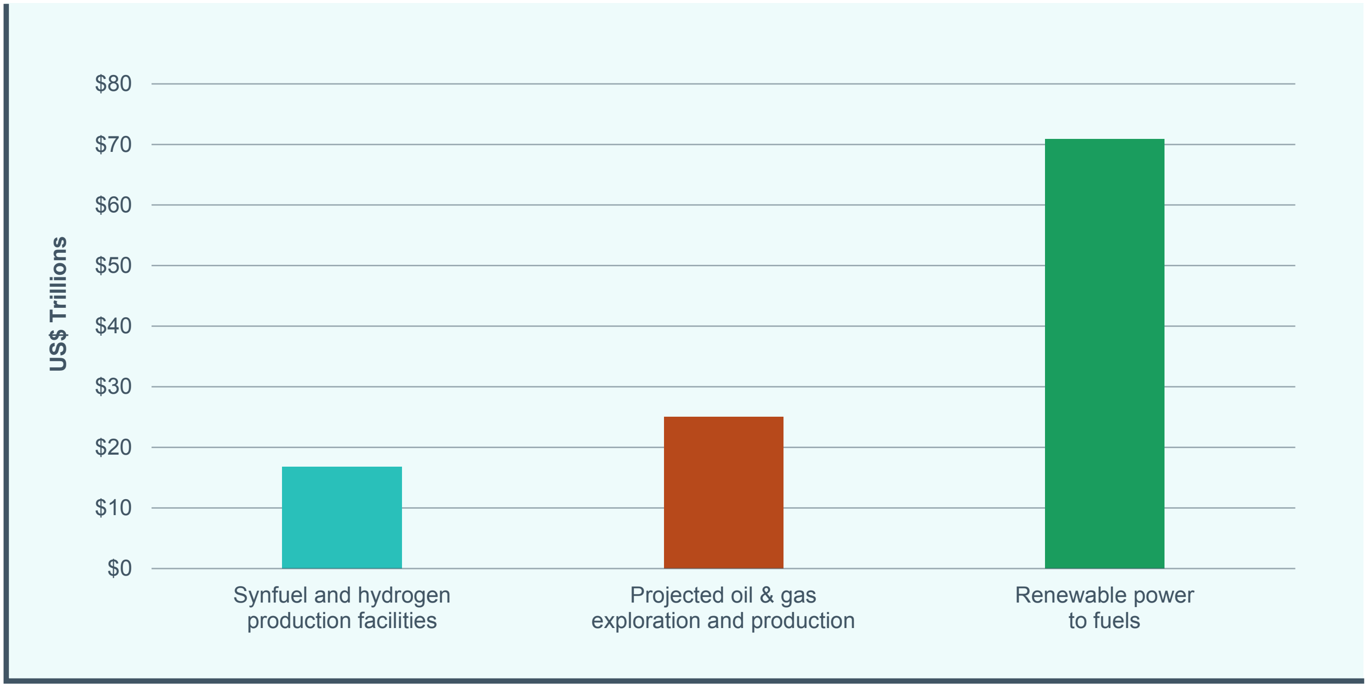
Figure 22 shows the investment required to transform the relevant fuels markets (assuming hydrogen and synthetic fuels produced from Gigafactories and production platforms) between 2025 and 2050. This case supplies 350 EJ and includes the full capital cost of these synthetic fuels production facilities, resulting in an investment requirement of $8 trillion less than the projected investment to maintain the equivalent flow of oil and gas. The implication is that **these fossil fuel markets could be replaced with clean substitutes within three decades for less investment than would be required to maintain them**.

Figure 22. **Cumulative investment in hydrogen-based fuels substitution to fully decarbonize fuels markets by 2050**



In contrast, attempting to achieve this supply of clean synthetic fuels with renewables-only hydrogen would require an investment of $70 trillion, as indicated in Figure 23 below.

Figure 23. **Comparative investment for fuel substitution by 2050**



The production platforms investment case assumes a weighted average installed cost over the 2030–2050 period of US$1.3 billion per GW-class production platform including electrolyzers, fuel production equipment, and onboard storage. The renewables investment case averages the costs of wind and solar in 2030 and 2050 to arrive at a weighted average installed cost for a combined wind-solar-electrolyzer project (with ratio of 1 MW wind: 1 MW solar: 1 MW electrolyzer) of approximately $2,000/kW.[43]

5.1 Rate of Deployment

Can this scale and rate of deployment be achieved in the real world? The industry delivering this transition would need to deploy more than the current global nuclear fleet capacity annually—that means adding approximately 490 GWe each year from 2025 to 2050.[44]

To provide an idea of current global production capacity, the world's shipyards produce btween 1,500 and 3,500 ships per year and are currently operating at approximately 50% capacity.[45] Many of the products currently being made in these shipyards are production platforms for the oil and gas industry, such as the Petronas FPLNG Dua (which is significantly more complex than the production platforms proposed in this report). It is also likely that in addition to utilizing excess capacity, the manufacturing capacity dedicated to existing fossil fuel-oriented platforms would be repurposed for synthetic fuels production platforms.

An advanced heat source company recently completed a study to have its plants manufactured in a large shipyard in Korea. This not only provided confirmation that of the costs used in this report, but suggested that a single large shipyard, without any investments to expand production, would be able to manufacture as many as 40 power-plant-sized ships (at 500 MW each) per year—20 GW per year. This shipyard represents less than 5% of global capacity.[46]

5.2 Achieving the Rate and Scale of Deployment Required

In the last five years there has been a substantial consolidation of shipyard capacity, with a number of smaller and less efficient shipyards closing down. As of 2019, there were 281 active shipyards in the world.[47] As shown in Figure 24 below, the full substitution of the oil and gas industry by clean synthetic fuels can be accomplished from the dedicated production of 64 shipyards.

The investment pull from these clean substitute fuels markets could drive further expansion in both the number of qualified shipyards and the output from these shipyards. Figure 24 shows rates of shipyard capacity coming online and plant output capacity. Shipyard starts in Figure 24 includes existing shipyards achieving full capacity, and being expanded or upgraded, as well as new shipyards starting production over time.

Figure 24. **Shipyard starts and cumulative operating shipyards**

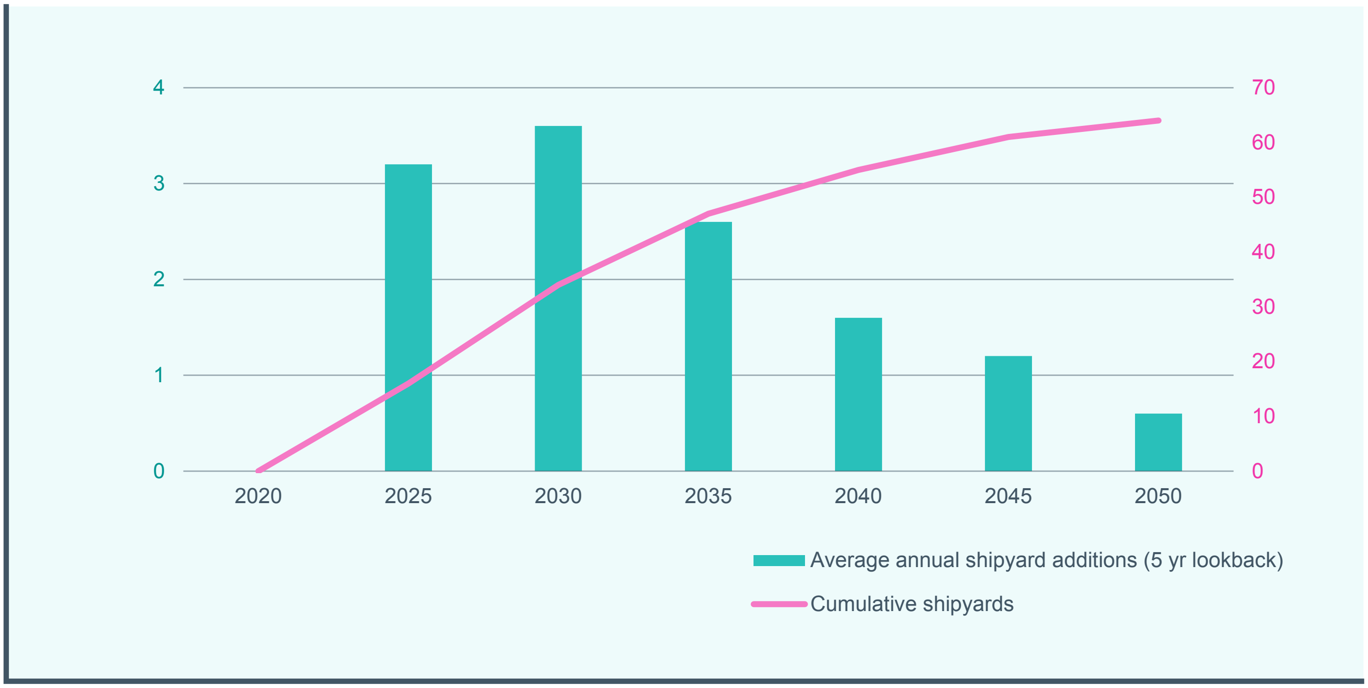


Figure 25 on the next page shows the achievable rate of delivery of production platforms and cumulative fleet size enabled by this increasing shipyard capacity. The combination of available (and increasing) shipyard capacity and potential for growth associated with expected demand for competitive clean substitute fuels enables rates of deployment that could feasibly replace fossil fuels within thirty years. Potential fossil fuel substitution from these rates of deployment within the 2020–2050 timeframe is shown in Figure 20 on page 38.

5.3 Production Platform Business Model Enables Financing at Scale

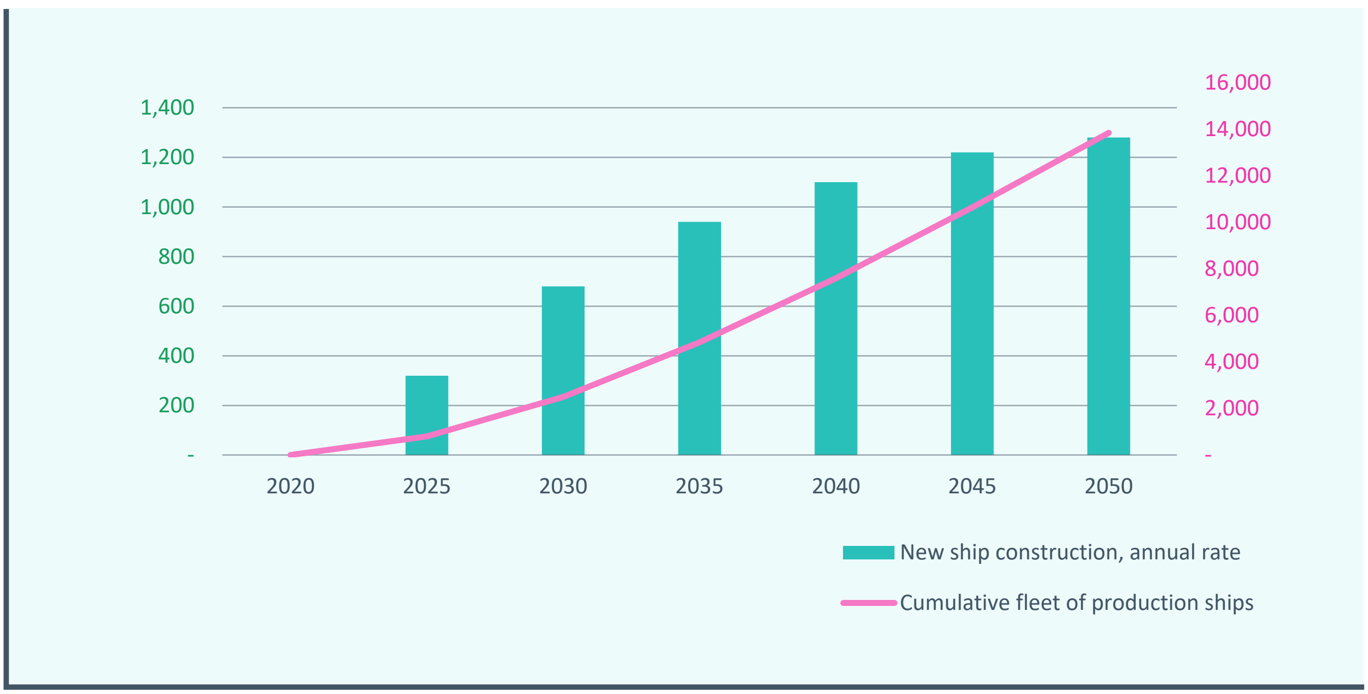
The total amount of investment required to decarbonize the liquid fuel sector by 2050 is lowest for the synfuel production platforms strategy articulated in this report, (see Figure 26 on page 45). However, it still requires a significant amount of capital—$16.7 trillion. Although this is less than the $25 trillion that the oil and gas industry expects to invest between now and 2050, to attract this scale of capital these production platforms must be better investments than business as usual. We believe that this new business model can offer higher risk-adjusted returns. Shipyard manufactured synfuel production platforms will have the characteristics of some of the most attractive large asset classes and will not have the carbon risk associated with long-dated investments in fossil fuel assets.

Shipyard manufactured synfuel production platforms will be able to become a large asset class because the business model will eliminate or mitigate key financial risks. Shipyards offer delivery guarantees on cost and schedule, especially once the first units in a new class have been completed. This is critical to enable project financing. Revenues can be de-risked through performance guarantees. These ensure that the equipment will perform to produce the expected amount of synfuel and long-term contracting/hedging will result in the expected price. Long-term, consistent, and predictable output from the production platforms will make them less risky than oil and gas production assets in this regard.

Because they are not tied to a specific set of production wells in a specific country, these assets will have much lower exposure to sovereign risks, such as currency risk and expropriation. They can also be moved if the local market or production environment becomes unattractive. This will also enable full insurance, on a commercial basis, for the asset value at a much lower cost than projects must pay to multilateral guarantors today. The risk that contracted customers may not be able to follow through on their contracted purchases—counterparty risk—is largely mitigated because there are large and liquid international markets for the products of the platforms, which can be easily shipped to other customers, thus ensuring continued revenues for the production platform.

Oil and gas companies are valued on reserves as well as cash flows from current operations, and the future value of those reserves is being questioned. Many oil and gas exploration and production investments—and company valuations—rely on the expectations of very low carbon prices and minimal restrictions on carbon emissions for decades into the future. The extent to which this risk should be priced into current company valuations is the topic of robust discussions among investment analysts today, and the pressure to do this will only increase. A business strategy that leverages these production platforms will not be exposed to these carbon risks, and is likely to grow in value over time.

Figure 25. **Additions and cumulative production facilities**



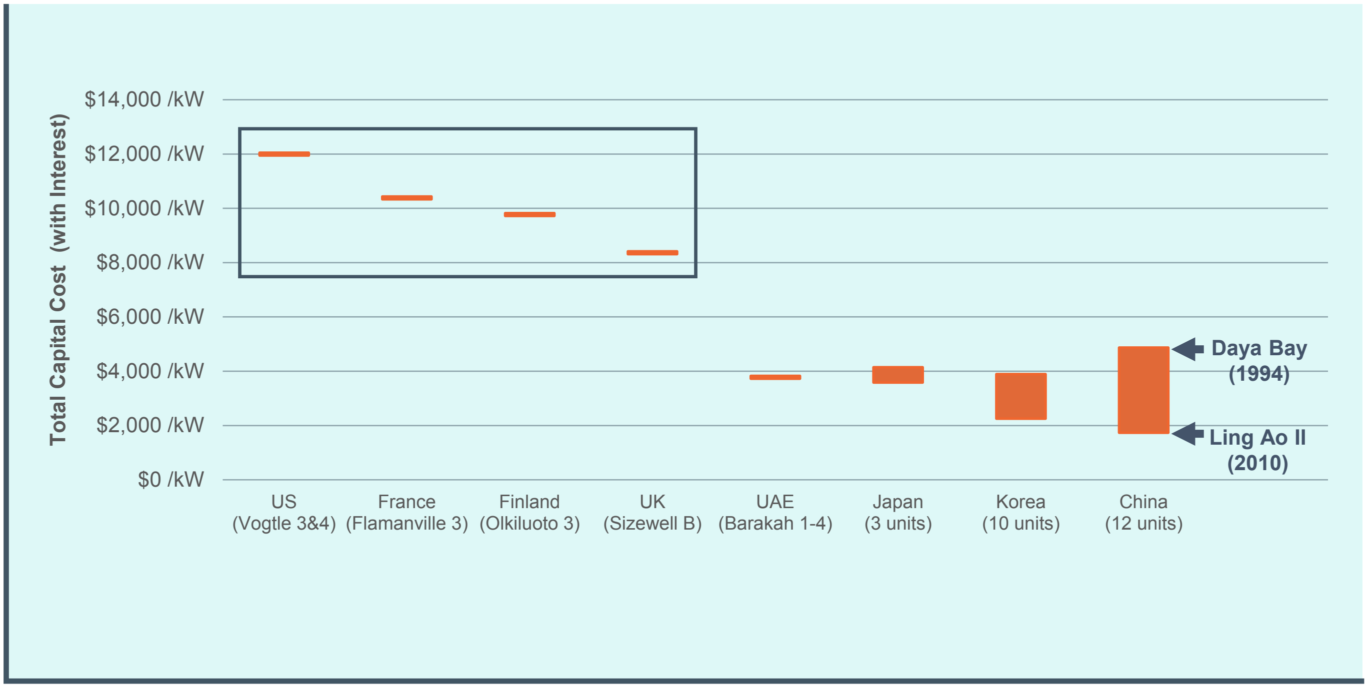
6 Cost Reduction from Shipyard Manufacturing

Why are costs for the shipyard manufactured production platforms so low? The cost reduction from manufacturing these facilities in leading shipyards is very substantial compared to the traditional approach to building plants. We group these sources of cost reduction into four categories and show how they explain the difference between observed costs of constructed nuclear plants in Europe and Asia, and the costs of the production platforms we use in this report. Broadly speaking, cost reduction comes from 1) costs that you don't have in the shipyard model, 2) increases in productivity from the shipyard manufacturing environment, 3) fundamentally different technology choices, and 4) ongoing learning, process improvement, and competition throughout the supply chain.

6.1 Costs that are Part of Traditionally Constructed Plants, but Absent from the Shipyard Environment

To understand the potential for cost reduction, it is helpful to look in a little more detail at the range of costs for nuclear plants being built today. In Figure 26 on the next page, we see that there is already a range of approximately 4-times between the majority of lower-priced plants and the few plants that are at the high end of the range. The plants at the high end of the range are all first of a kind (in that country), first in a generation, and have required substantial capacity building in the local regulator, supply chain, and labor force. These first-in-a-generation costs are substantially higher than the costs of building a new design, but with an industry, supply chain, permitting process, and regulator that is experienced with nuclear construction. In addition to the direct costs of these factors, long build times for first of a kind plants (7–10 years), require substantially larger time-based indirect costs, such as project engineering and supervision, quality inspection, and rental of site infrastructure. For expensive projects, these indirect costs can equal or exceed the direct expenditures on labor, equipment, and materials. Longer duration projects, with higher expenses, accumulate more interest during construction, and pay higher interest rates due to project risk, further adding to the final cost of these projects. Due to inexperience building the new designs, and the first in a generation learning curve, there are frequently delays, extending the project schedule and further adding to costs.

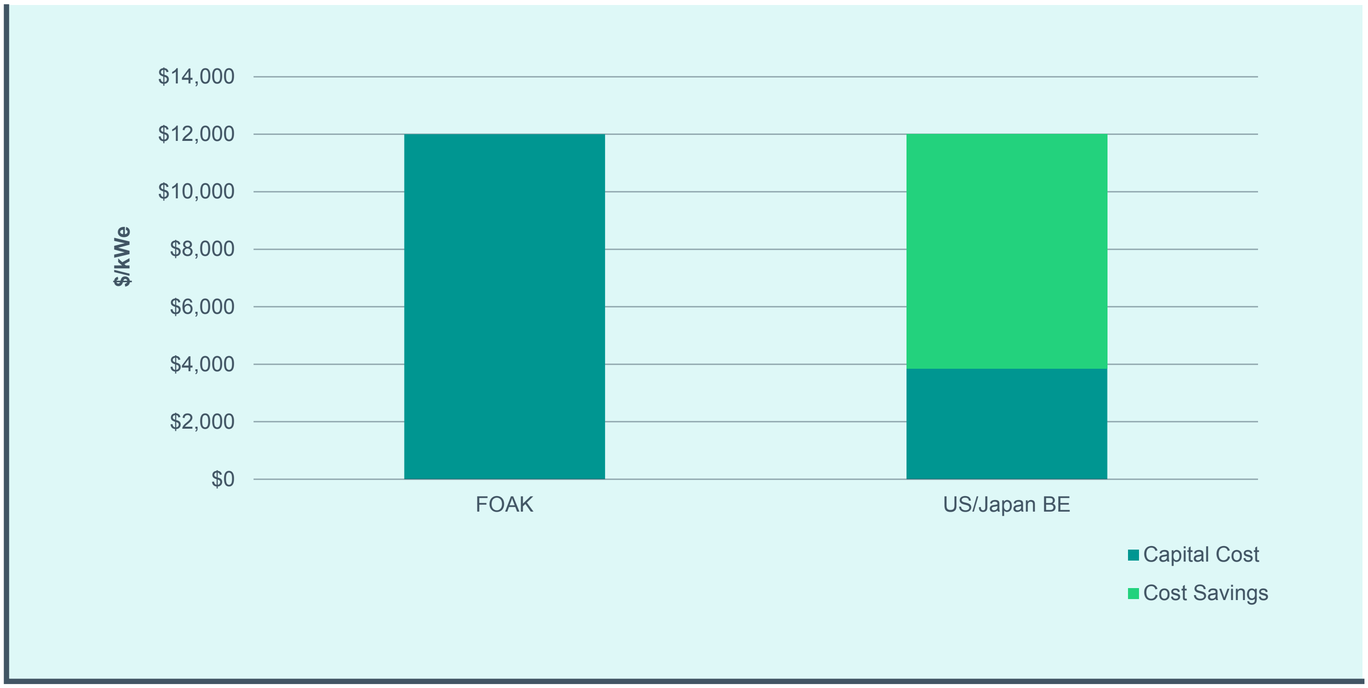
Figure 26. **Costs of recent nuclear plants**



Source: LucidCatalyst, Eric Ingersoll, Kirsty Gogan, et al., "The ETI Nuclear Cost Drivers Project: Full Technical Report," September 2020.

By comparing these few first of a kind plants to the larger number of plants being built as part of continuous build programs, (in Japan, Korea, China, and Abu Dhabi) we can see that the 'program build' plants are three-quarters of the cost of the expensive plants. There are well-understood reasons for these high costs, but they are not relevant to a continuous production environment like an established world class shipyard. Data from the most recently built 30 nuclear plants suggests that these first of a kind and first in a generation extra costs are as much as $8,000/kWe—the difference between $12,000 and $4,000/kWe.[48]

Figure 27. **Cost reduction from first-of-a-kind (FOAK) to program build**



6.2 Cost Reduction from Increased Productivity in the Shipyard Manufacturing Environment

As we move our project to a modern shipyard, there will be two broad classes of cost savings; avoided costs (such as buildings) and reductions in remaining costs (such as equipment installation) due to the highly productive shipyard environment.

Next we look at the lower cost plants in "Figure 26. Costs of recent nuclear plants" on page 45: those in the $4,000/kWe range. Even though these are much more cost effective, they still have substantial costs that are not present in a shipyard manufacturing environment building repeated units from a standardized design. Examples of these avoided costs include, site specific engineering and design, site civil works and excavation, site mobilization, temporary site facilities, buildings, concrete (foundations and other non-buildings uses materials, labor, inspection), temporary structures, site security, equipment rental, roads and parking, etc. Even in these very cost-effective projects, these can account for more than 50% of the total overnight cost.[49] In addition, a large construction site has to have a dedicated project management organization, with the costs for all administrative (IT, HR, training, accounting, etc.) functions being carried by the project. While these administrative functions also exist in a shipyard, they do not have to be set up as they are built into the ongoing overhead for the whole yard and represent a much lower percentage of the cost of producing the platform.

Due to extreme international competition between world class shipyards, they have developed highly productive engineering and manufacturing processes. Each shipyard has its own dedicated design team. These designers are expert at designing to achieve the required quality while achieving the lowest possible cost—taking advantage of the established production processes in their shipyard. This includes design for automation of labor-intensive processes, reuse of design components, and careful design of equipment and tools to enable highly productive, high-quality work. Because the ships are manufactured in modules, the manufacturing teams are able to repeatedly work on the same types of modules, practicing intensive continuous improvement, gaining efficiency and avoiding errors and/or practices that waste time. Standard productivity for manufacturing a curved hull and internal structures is five person hours per erected ton of steel. This productivity is what enables a large container ship of approximately 400m in length, with a capacity of 23,000 Twenty-Foot Equivalent Units (TEU) shipping containers, to be built for $150 million.[50] In fact, since the first orders for these ultra-large containerships, costs of the ships have declined 20% and their capacity has increased from 18,000 to 23,000 TEU.[51] This is a reduction in capital cost per unit capacity of 38% in less than 7 years.[52]

For the simpler flat construction of the production platforms described in this report, automated panel lines can reduce this to two person hours per metric ton of steel. These costs result in an erected and assembled cost of less than $1,000 per metric ton.[53] A 1.2GWe production platform will require ~150,000 metric tons of steel for hull and structures, costing approximately $150m fully assembled, and taking less than a year to build. This substitutes for all of the structures in the traditionally delivered $4,000/kWe plant.[54] These buildings cost ~$1-1.2 billion on a fully loaded basis, for an equivalent size plant. Comparing the labor hours required explains this divergence. The ship hull and structures require approximately 750,000 hours, whereas the buildings at the cost-effective nuclear plant require more than 8,000,000 hours of engineering, direct labor, and construction supervision. This improved productivity in the shipyard also reduces the cost of installation of piping, electrical and mechanical equipment—costs that are included in a separate category—and time critical tasks such as inspections and commissioning. In the shipyard, most of these outfitting and inspection tasks will be accomplished at the module level, ensuring completion and compliance, before the final assembly of the modules. This enables any errors to be corrected before they can affect the schedule, which is typically driven by final module assembly.

These cost improvements are summarized in Figure 28 below and detailed in Table 4 on the next page.

Figure 28. **Costs avoided through shipyard manufacture**[55]

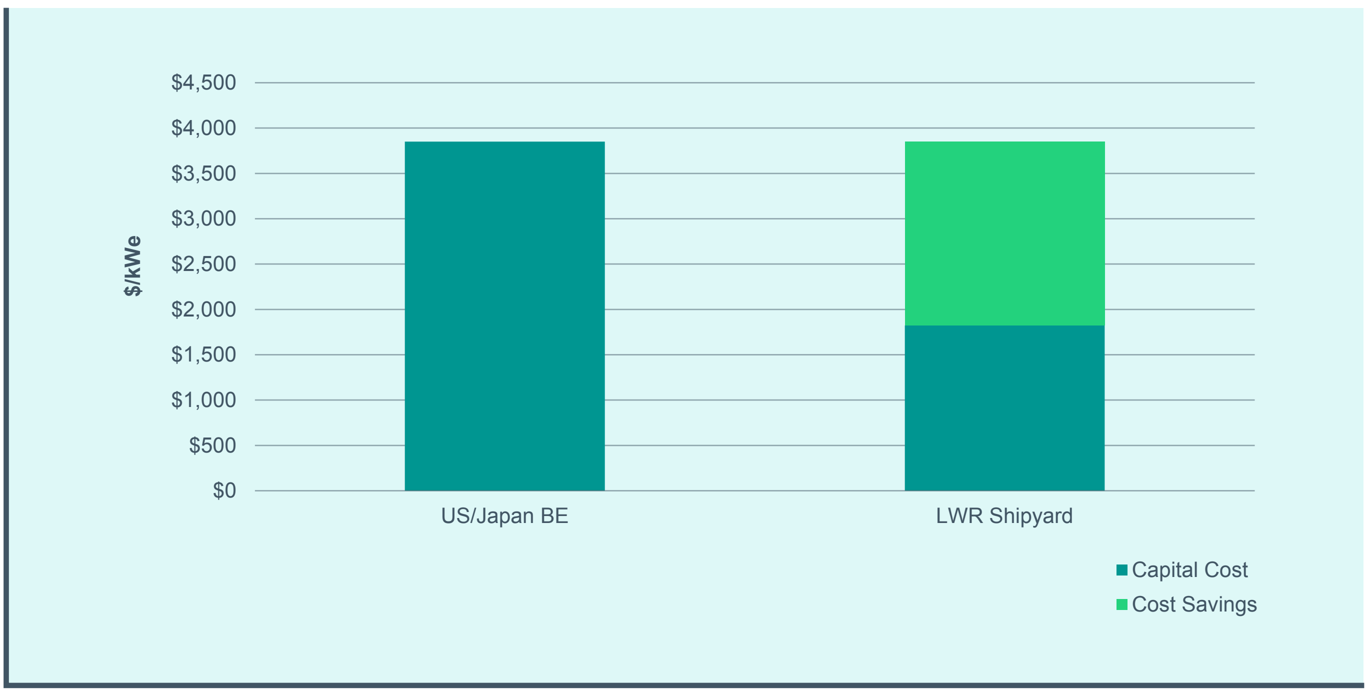


Table 4. **Detail on costs avoided through shipyard manufacture**

Cost Acct	Program Build to Light Water Reactor (LWR) Shipyard	Benchmark	Shipyard Savings	Remaining Cost	Notes
10	Pre-development Costs	$175/kW	($153/kW)	$22/kW	Simpler siting/permitting
21	Structures and Improvements	418	(287)	131	Replaced by hull
22	Reactor Plant Equipment	630	(51)	580	Improved installation productivity
23	Turbine Plant Equipment	466	(44)	422	Improved installation productivity
24	Electric Plant Equipment	169	(36)	133	Improved installation productivity
25	Misc Plant Equipment	97	(24)	74	Improved installation productivity
26	Main Heat Rejection System	102	(16)	86	Improved installation productivity
	Total Direct Costs	**2,057**	**(610)**	**1,447**	
91	Construction Services	472	(472)	-	Built into shipyard
92	Engineering and H/O Services*	443	(408)	35	Nth of a kind (standard design)
93	Field Supervision	232	(179)	52	Quality built into production process
	Transport, Installation			109	
	Total Indirect Costs	**1,146**		**197**	
	Total Overnight Costs	**3,203**		**1,644**	(Direct plus Indirect Costs)
	Interest During Construction	648		179	
	Total Cost	**3,851**	**3**	**1,823**	

* H/O = "Home Office" refers to costs that are incurred at the home office (rather than at project site).

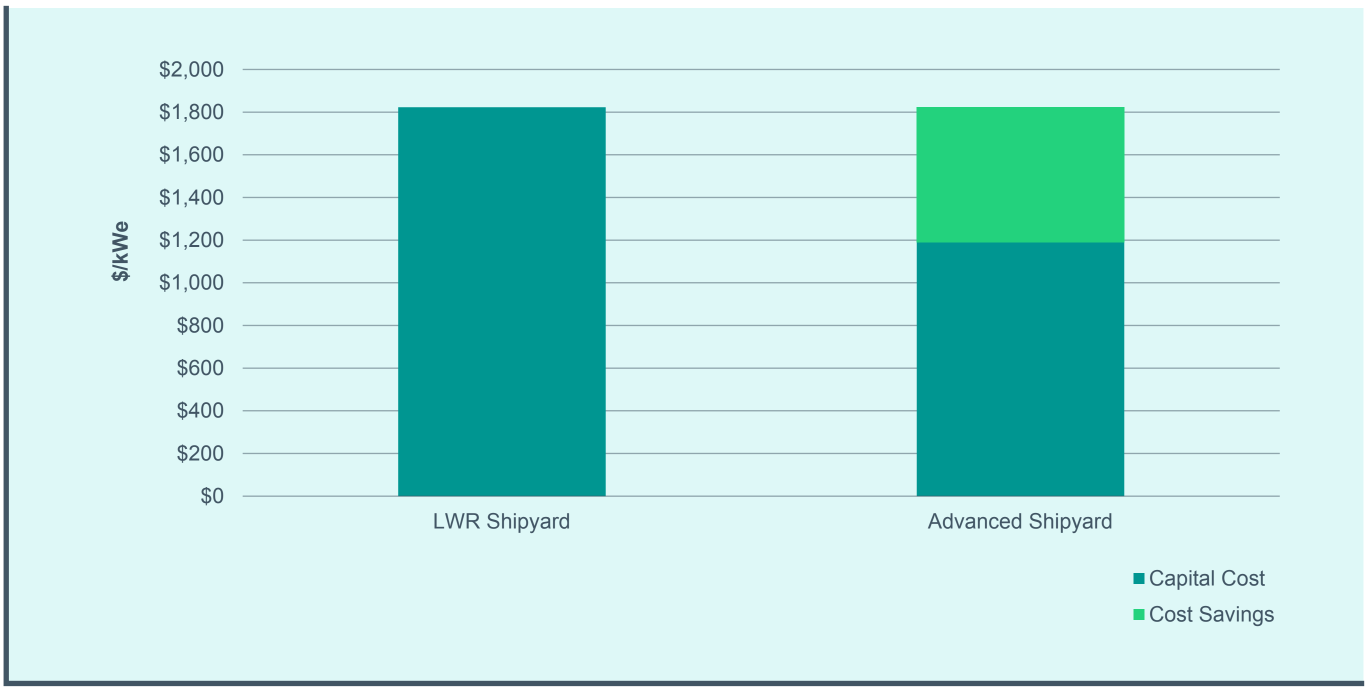
Another indication of the higher productivity of the shipyard environment is a comparison of the person hours required for the design and construction of a large commercial nuclear plant and a Floating LNG Processing platform, such as the Petronas FPLNG Dua. The Dua was the second such platform build for Petronas, but it was a completely new design, incorporating learnings from the earlier unit. Design, procurement, building, and commissioning required 16 million labor hours.[56] This is for a plant that is the same size as, but considerably more complex than, the production platforms in this report, and it includes all the non-recurring design, chemical process engineering, procurement of components and equipment, and production engineering. These non-recuring costs may be as high as 50% of the total hours, and the remainder could drop by 40% over an order of 10 identical units. The similar design-build process for the cost-effective nuclear plant is 32 million person hours.[57]

There is another important result of building the production platforms out of known components and well-established shipyard production processes. We know that these highly predictable costs represent more than 90% of the total manufacturing cost of the production platform. Thus, we can be highly confident in about 90% of the costs, and even if the remaining costs were two or three times higher than estimated, this would represent at most a 20% increase in the total cost.

6.3 Cost Reduction from Advanced Nuclear Technology

We have so far seen how by firstly eliminating first-of-a-kind costs, and then moving to the low-cost, high productivity shipyard manufacturing environment, this enables the elimination of whole categories of costs and the dramatic reduction of the labor costs that remain. At this low level of cost, the costs of the nuclear components and other equipment become a much larger percentage of the remaining cost. At this point, the features of advanced reactors can enable significant further reductions in capital and operating cost. These include dramatically reduced complexity of safety systems, no need for pressure capable containment, elimination or reduction in thickness of reactor pressure vessel, etc. For example, the full list of equipment needed for our $1,823/kWe shipyard manufactured LWR plant is just over $1,030/kWe (not including installation). The comparable set of equipment for a molten salt design is $565/kWe—a $465/kWe reduction[58] (see Table 5 on the next page). In most cases, these not only eliminate components, and lower capital costs of the remaining items, but they reduce the size, and cost of, structures required for these components. Based on our comparative studies of shipyard manufactured plants based on Light Water SMR and Molten Salt SMR technologies, we have identified another $100/kWe in savings related to structure and reduced installation labor. Furthermore, this lower cost equipment and the lower cost structure will be operating at higher temperature, it will be 35% more efficient further lowering overall cost by about 25%. The simplicity will also likely result in fewer items to maintain as well as simpler maintenance, reducing staffing and other operational costs.

Figure 29. **Cost reduction from advanced heat source technology**



6.4 Ongoing Learning and Cost Reduction in Series Production

World class shipyards have repeatedly demonstrated that they can innovate to lower manufacturing cost and improve product performance. In the last 15 year there has been an ‘arms race’ between the most competitive yards, to develop the most integrated design and manufacturing processes, and to move deeper into product design and product innovation, rather than just be a builder of others’ designs. Once the basic architecture of the shipyard power plants, and their fuel production platform cousins become established, we would expect the same rapid cost reduction and product improvement that we have seen

Table 5. **Cost reduction from shipyard manufactured light water reactors (benchmark) to advanced heat technology**

Cost Acct	LWR Shipyard to Advanced Heat Source Technology	Bench-mark	Cost Reduction	Remaining Cost	Notes
10	Pre-development Costs	$22/kW	$- /kW	$22/kW	No change
21	Structures and Improvements	131	-	131	No change
22	Reactor Plant Equipment	499	-	-	Lower cost reactor, see subtotal
23	Turbine Plant Equipment	361	-	-	Lower cost turbine, see subtotal
24	Electric Plant Equipment	68	-	-	Similar electric plant costs, see subtotal
25	Misc Plant Equipment	39	-	-	Similar misc equip costs, see subtotal
26	Main Heat Rejection System	64	-	-	Lower cost condenser sys, see subtotal
	Total Equipment	1,030	(466)	565	
	Total Installation	264	(106)	158	
	Total Direct Costs	**1,447**	-	**876**	
91	Construction Services	-	-	-	
92	Engineering and H/O Services*	35	-	35	
93	Field Supervision	52	-	52	
	Transport, Installation	109		109	
	Total Indirect Costs	**197**		**197**	
	Total Overnight Costs	**1,644**		**1,073**	(Direct plus Indirect Costs)
	Interest During Construction	179		117	
	Total Cost	**1,823**		**1,190**	

* H/O = “Home Office”—refers to costs incurred at the home office (rather than at project site).

in container ships; drill rigs; floating production, storage, and offloading facilities (FPSOs); and all of the other standard products of the leading yards.

In “Rethinking Deployment Scenarios to Enable Large-Scale, Demand-Driven Non-Electricity Markets for Advanced Reactors,”[59] we have provided more detail about the direction these innovations may take. Collectively, cost reductions of ~20–25% seem eminently achievable and performance (platform rating, or output) increase of 20–25% within the same footprint is also possible. These improvements would lead to the cost reduction shown in Figure 30 on the next page.

Figure 31 shows the evolution of the cost reduction from first-of-a-kind and first-in-a-generation with extremely high costs for restarting capability in the nuclear regulator, supply chains, and complex project construction; to the costs associated with continuous program builds to the cost savings from manufacturing in shipyards; to the costs associated with advanced heat source technology and mass manufacturing.

Figure 30. **Further cost reductions from ongoing design improvements and manufacturing process improvements**

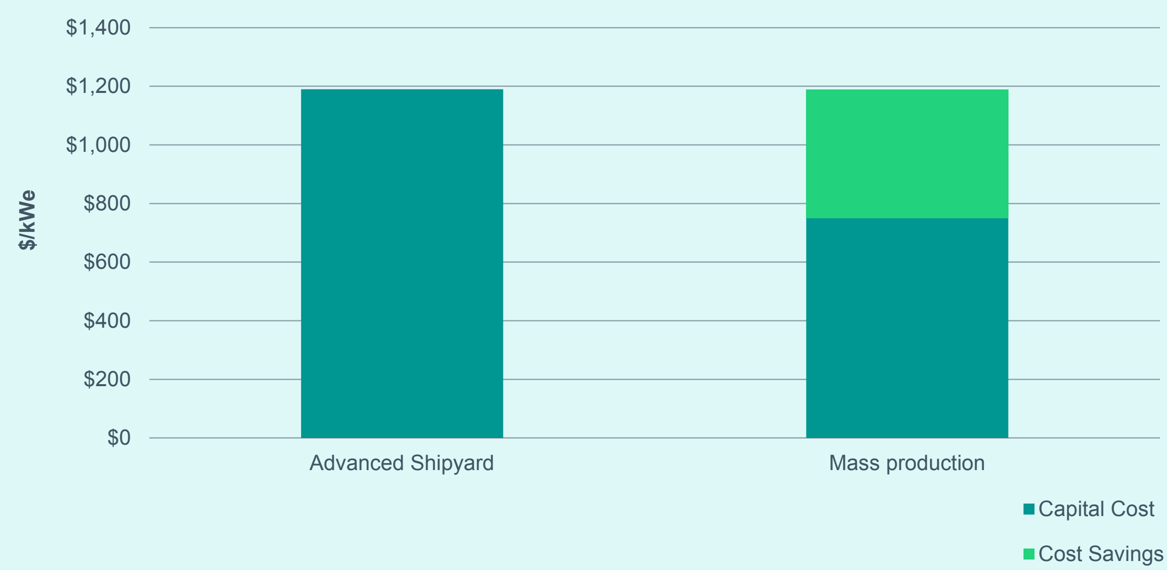
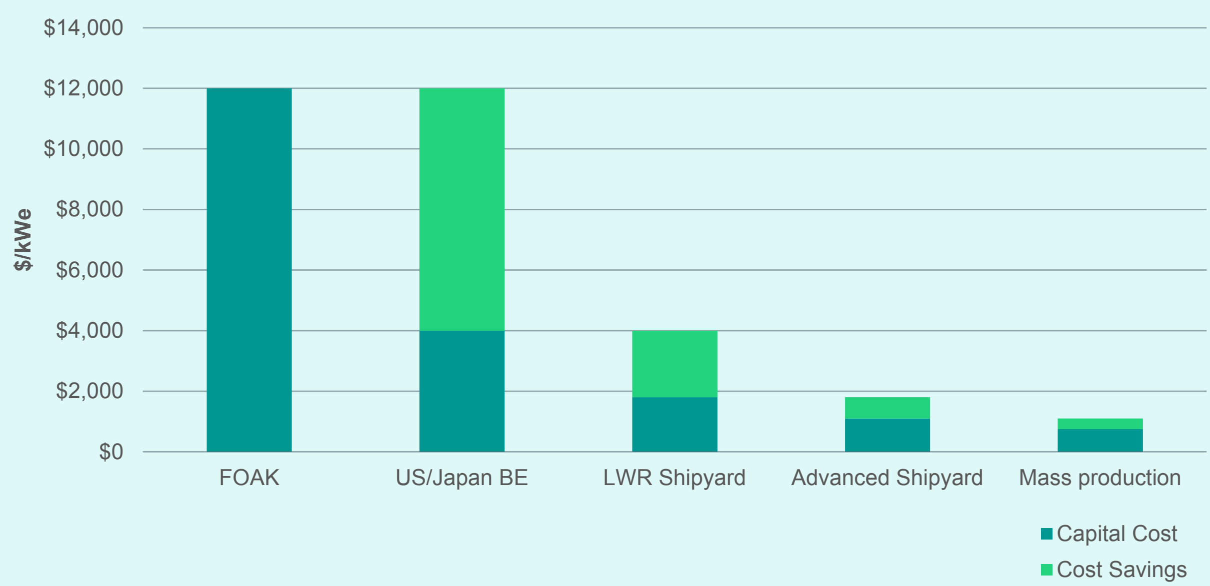


Figure 31. **Evolution of cost reduction from first-of-a-kind construction projects to mass manufactured products**



7

Physical Space Constraints: A Reality Check

To achieve the lowest cost renewable-hydrogen, it is possible to co-locate wind and solar projects, in the best combined wind and solar resources, to deliver high capacity factors and hydrogen at around $2/kg within the 2030 timeframe. However, most of these locations are remote from populations and markets. Adding distribution costs from remote locations, for example, Australia to Japan, increases costs from $2/kg to $3.3/kg. This raises the cost beyond the threshold of economic competitiveness ($0.90/kg), which this report describes as essential to achieve widescale substitution of fossil fuels.

Irrespective of costs, it is not realistic to expect renewables to be able to produce hydrogen in large quantities at the same time as decarbonizing grid electricity in most advanced economies because of sheer physical space constraints.

Even assuming a relatively high solar capacity factor for entirely hot desert installation (25%), PV farms equivalent to the entire installed capacity of Germany in 2020 (50 GW) would need to be installed globally every 10 days from now until 2050 for solar hydrogen to cover world projected demand.[60] If hydrogen were to be entirely supplied with offshore wind, for example (and accounting for wind's capacity factors), an amount roughly equivalent to the United Kingdom's entire current offshore wind fleet (9 GW) would have to be built every three and a half days around the world right away until 2050.[61]

This issue is not widely appreciated by many of those who are most enthusiastic about a renewables-only 'hydrogen economy', so we offer some scale drawings below for Japan, the UK, and South Korea to illustrate the enormous differentials in area required for hydrogen production between wind, solar and advanced heat sources.

It could be argued that a proportion of oil consumption will be decarbonized through other means, for example the direct electrification of surface transport, and that therefore these projections are unduly pessimistic. However, the converse is actually likely to be true: hydrogen will be required to replace much more than oil; in the UK natural gas is used in heating, while heavy industry overwhelmingly depends on solid fossil fuels like coke for steelmaking. Accordingly, we share these maps with the caveat that they are for illustrative purposes and are not intended as exact projections of specific decarbonization technology pathways.

We believe these exercises are useful because much of the energy debate neglects the issue of scale and required land-use, and numbers expressed in tens or hundreds of thousands of square kilometers are hard to visualize. The enormous scale required for energy-diffuse renewables to substantially replace energy-dense fossil fuels is not just an increase in the number of gigawatts built but will be a qualitatively different set of impacts in terms of numbers of people affected and competition for land. These risks increase with scale of deployment—given conflicts with ecological and food-production goals, and the prospect that public protests will increase, well before the kinds of country-sized developments required for green hydrogen will ever be built. We make this argument not to discourage deployment of renewables, but to encourage the development of realistic strategies for decarbonization that include a range of technologies that do not all share the same risks.

The idea that we can achieve decarbonization with renewables alone and should therefore exclude other technologies from the definition of 'green' and from accessing climate finance, and that developing countries should plan their economic growth on renewables alone, is a toxic idea that creates unnecessary conflict within the groups of people working on solving climate change. This misplaced emphasis on the means (technology) rather than the goal (decarbonization) also prevents any possibility of meaningful conversations about progress.

7.1 National Scale Hydrogen Production: Energy and Area Requirements

This section analyses the area required to produce an amount of hydrogen equivalent to annual oil use for a country. We examine this for three energy production technologies: solar PV, offshore wind, and advanced heat sources. Table 6 shows the assumptions used, including capacity factors, power density and other variables—behind these projections.

There is a stark difference in the energy produced per square kilometer. Consequently, the geographic area required to produce hydrogen from wind and solar is dramatically higher than from advanced heat sources. The power density differential matters, as brilliantly explained in the late Professor Sir David MacKay's landmark book *Sustainable Energy Without the Hot Air*, and to whose memory this report is dedicated. While solar PV has a power density of 50 MW per km^2, offshore wind can deliver only 2 MW/km^2. This calculation includes the space between the turbines, to be more realistic. In contrast, advanced heat sources have a power density of 2,080 MW/km^2: about 500-times greater than solar PV and 1,200-times greater than offshore wind. In Table 7 below, we show the calculations to determine the area required for three illustrative high-income, land-limited countries which have dense populations and high per capita energy use—the UK, Japan, and South Korea.

Table 6. **Calculations of energy production and hydrogen production for wind, solar, and advanced heat sources for the UK, Japan, and South Korea**

	Solar PV	Offshore Wind	Advanced Heat Sources
Power Density (MW/km^2)	50	2.3	2,080
Capacity Factor	12%	50%	90%
Specific Annual Energy Production (GWh/km^2/year)	52.6	9.1	16,399
Specific Annual Hydrogen Production (Tonnes/km^2/year)	968	167	466,979

Calculation Sources: PV calculated from the list of the largest photovoltaic power stations, Wikipedia; Andrew ZP Smith, ORCID: 0000-0003-3289-2237; "UK offshore wind capacity factors" (note that the power weighted average capacity factor for UK offshore wind is 40% but newer projects are expected to have higher capacity factors, therefore, we used 50%); Advanced Heat Source is the average of Hinkley Units A, B, C (2,427 MWe/km^2) and Hanbit Nuclear Power Station in South Korea (1,733 MWe/km^2). Note that offshore production platforms and the onshore Gigafactory would both have higher power density.

Table 7. **Annual oil consumption in the UK, Japan, and South Korea (2019)**

		UK	Japan	South Korea
Oil Consumption (BOE/year) (LHV)*		575,925,926	1,394,444,444	981,481,481
Oil Consumption in Exajoules (EJ)		3.11	7.53	5.30
Annual Hydrogen Equivalent (Tonnes)		25,895,087	62,697,752	44,129,892
Solar PV for Hydrogen Production	MWe	1,304,464	3,158,396	2,223,041
	km^2	26,090	63,170	44,460
Offshore Wind for Hydrogen Production	MWe	313,070	842,240	592,810
	km^2	136,120	366,190	257,740
Advanced Heat Sources for Hydrogen Production	MWe	115,342	279,269	196,564
	km^2	55	134	95

* BOE = barrels of oil equivalent. Calculated from exajoules on an LHV basis.

7.2 UK Hydrogen Production Geographic Area Requirements

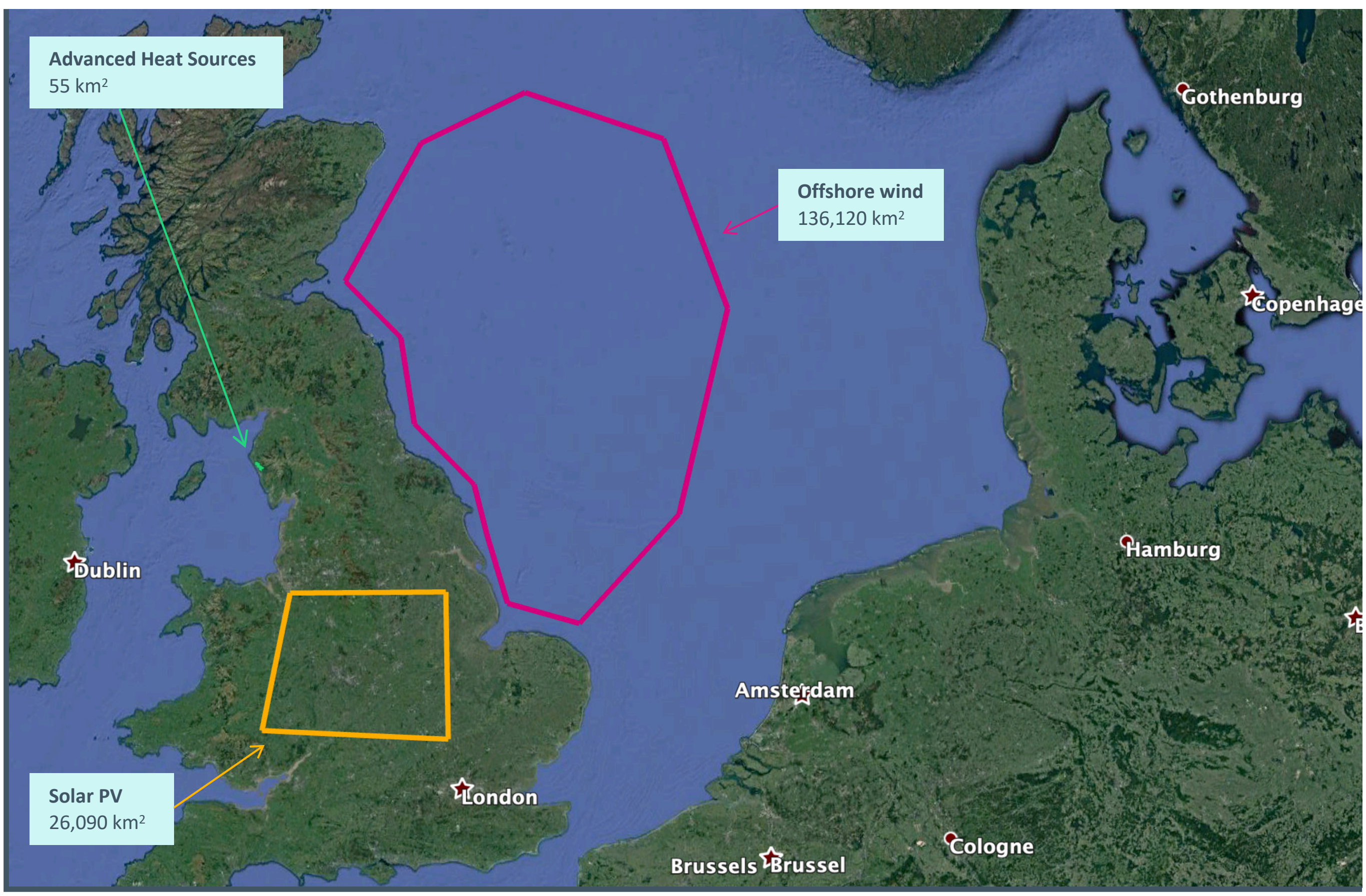
Our first case study is the UK, a high-income country with high energy use per capita, and high population density. We calculate that for the UK to use solar PV-generated hydrogen to replace its current usage of oil would require covering an area of 26,090 km^2 (as illustrated by the yellow outline in Figure 32) with solar panels. (Note that these projections are simply to illustrate scale; we are not suggesting that projects should be built in these exact locations.)

To produce the same amount of hydrogen instead with offshore wind would require an area of 136,120 km^2—which would take up most of the North Sea. This pink outline shows the size of a single continuous wind farm to produce this much hydrogen.

If the UK were to produce the same amount of hydrogen for liquid fuels substitution using Gigafactories or production platforms with advanced heat, the land area required is dramatically smaller—requiring only 55 km^2—as illustrated by the barely visible green shape in Figure 32.

In the UK, a single 350 MW-capacity solar farm at Cleve Hill in Kent was opposed by Greenpeace because of its ecological impacts, despite Greenpeace's long-standing advocacy of solar power as a tool for decarbonization (the Royal Society for the Protection of Birds (RSPB) was also opposed, while Friends of the Earth was in favor).[62] Cleve Hill has an area of 387 hectares; we calculate that it would take 76 Cleve Hills—covering an area of 295 km^2—to generate the same amount of energy as the proposed Sizewell C nuclear plant, which has an area of 0.32 km^2.

Figure 32. **Comparing the total area required to replace the UK's current oil consumption with hydrogen generated from either wind, solar, or advanced heat sources**



Each colored outline represents the total area that would be required for the siting of each type of resource if it were to be the only one used to generate enough hydrogen to replace current oil consumption in the UK.

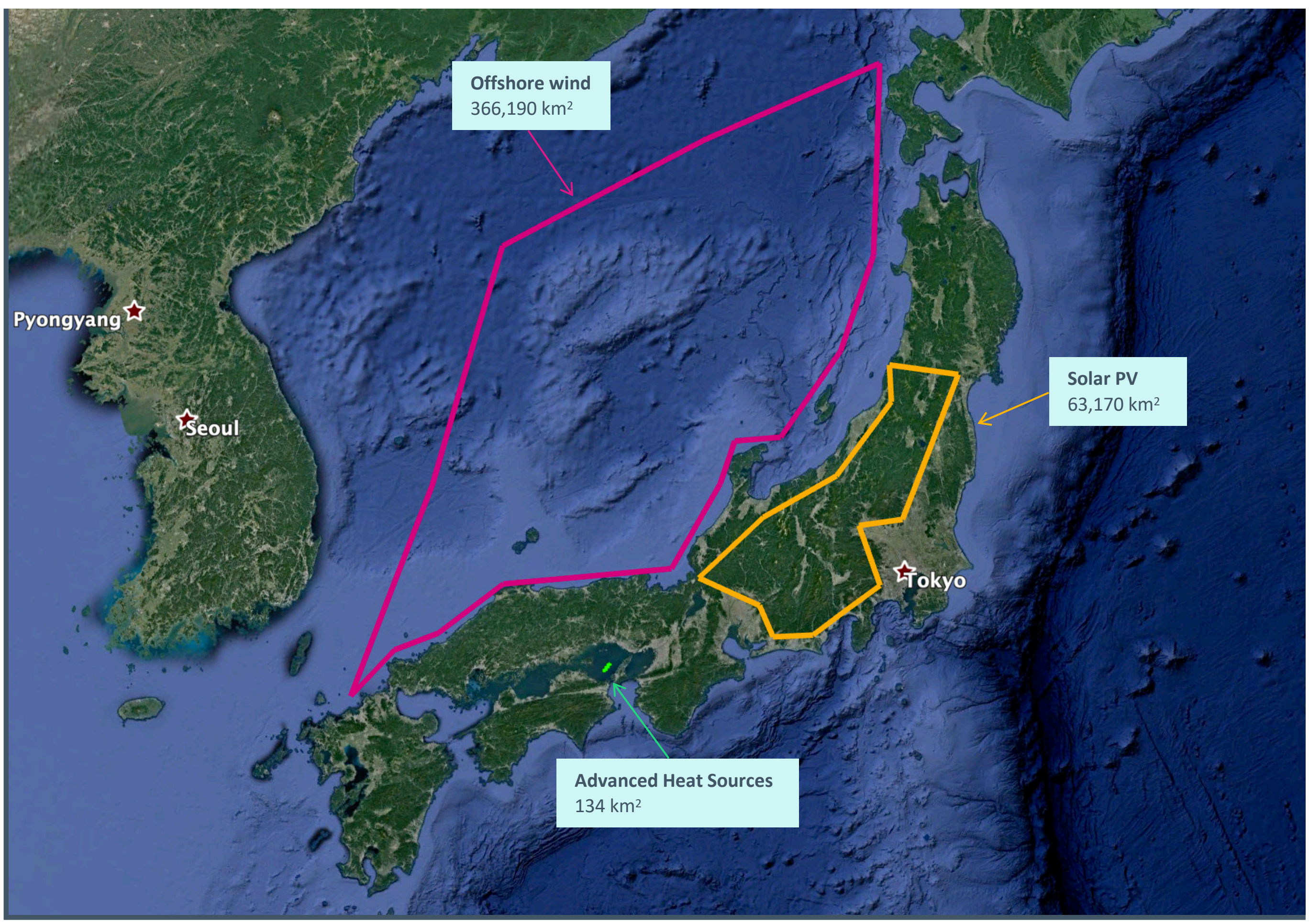
7.3 Japan Hydrogen Production Geographic Area Requirements

Japan is a particularly striking example as its mountainous and densely-populated territory has very little land available for the large solar farms that would be required for solar-generated hydrogen, and onshore wind faces similar geographical constraints. As Figure 33 above shows, the solar task is simply impossible to imagine—the area required for solar-generated hydrogen to replace Japan's current consumption of oil-based liquid fuels would be 63,170 km^2.

It has been suggested instead that Japan could use offshore wind in relatively deep water, although the area of shallow continental shelf required is also limited because of the Pacific subduction zone trench off Japan's eastern shore. Even floating offshore wind turbines will require anchoring to the seabed, so water thousands of meters deep will never be suitable. Consequently, we have shown the area required for offshore wind-generated hydrogen to replace Japan's current oil consumption—366,190 km^2—is a pink outline in the Sea of Japan on Japan's western shore. Given the scale required, it is easy to image that this could lead to conflicts with Japan's neighbors.

The area required for advanced heat sources, on the other hand, is so relatively small—134 km^2 —that it is not easily visible on the same map above.

Figure 33. **Comparing the total area required to replace Japan's current oil consumption with hydrogen generated from either wind, solar, or advanced heat sources**

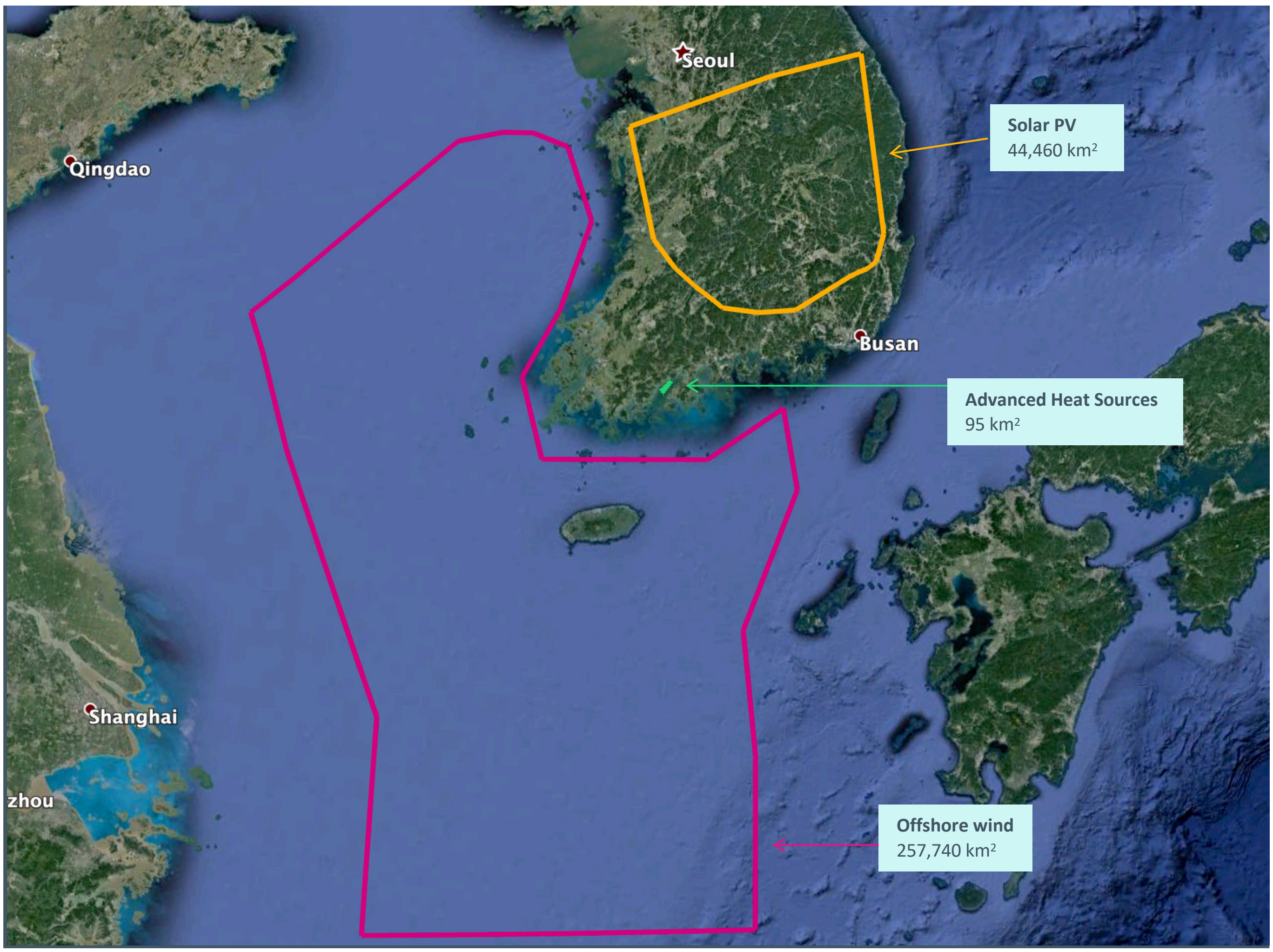


Each colored outline represents the total area that would be required for the siting of each type of resource if it were to be the only one used to generate enough hydrogen to replace current oil consumption in Japan.

7.4 South Korea Hydrogen Production Geographic Area Requirements

Our third example is South Korea, another high-income country with high energy use per capita and high population density (Notably, Japan, the UK and South Korea all deploy nuclear power currently, partly in order to address these concerns.) The yellow outline in Figure 34 shows the area that would be required to replace all of Korea's current oil use with hydrogen generated from solar PV—that is 44,460 km^2. If South Korea were to opt instead for offshore wind, the area required would take up most of the South China Sea—or 257,740 km^2—as illustrated by the pink outline in shows. The comparison with the land-take of advanced heat sources is stark, requiring only 95 km^2 represented by the barely visible green shape.

Figure 34. **Comparing the total area required to replace South Korea's current oil consumption with hydrogen generated from either wind, solar, or advanced heat sources**



Each colored outline represents the total area that would be required for the siting of each type of resource if it were to be the only one used to generate enough hydrogen to replace current oil consumption in South Korea.

7.5 Global Hydrogen Production Geographic Area Requirements

We do not show a map projection for the global comparisons, because in practice the locations of the renewables and production platform investments would be scattered in multiple locations. We have to assume that if counties are planning massive investments in clean energy that they will want to control those investments. However, the numbers are striking. For solar PV to replace all global oil using hydrogen, an area equivalent to 770,900 km^2 would have to be covered with solar panels—an area similar to the size of Turkey.

For offshore wind to replace global oil with hydrogen, an even larger area is needed. This adds up to 8,380,000 km^2, about the size of Brazil (8,460,000 km^2).

For the production platforms described in this report, powered by advanced heat sources, to do the same job—3,414 km^2 are needed, equal to a square of 58 km side length.

As stated repeatedly, these projections are not intended to represent exact energy pathways, but they do give a useful order of magnitude estimate—as David MacKay recommended in his work—to indicate the scale of the decarbonization challenge using different technologies. If countries do not have the land/sea area available themselves, as most will not, and still insist on a 100% renewables-generated hydrogen approach, this will need to be imported from abroad as a liquid fuel, raising the same geopolitical questions as today's liquid fuels market, which is dominated by a small cartel of producer countries.

Geopolitical questions such as this are outside the scope of this report, but the implication is clear: if nations want some semblance of energy security at the same time as replacing oil and gas with hydrogen, the majority will need to be generated domestically from advanced heat sources. This is especially the case if renewables are already earmarked to decarbonize the majority of electricity grid generation, which in itself will utilize extremely large areas of land and sea.

In short, we can conclude with confidence that the hydrogen economy is only viable on the scale and pace required if advanced heat sources are used alongside renewables in order to overcome geographical and cost constraints.

8 Conclusions and Recommendations

Given the scale and urgency of the required clean transition combined with growth of the global energy system, all zero-carbon hydrogen production options should be pursued. The potential of advanced heat sources to power the production of large-scale, very low-cost hydrogen and hydrogen-based fuels could transform global prospects for near-term decarbonization and prosperity. This report sets out a pathway to decarbonize a substantial portion of the global energy system, for which there is currently no viable alternative.

8.1 Conclusions

While it sounds daunting to achieve the scale of production needed, the scalability and power density of advanced heat sources are a major benefit. By moving to a manufacturing model, with modular designs, it will be possible to deliver hundreds of units in multiple markets around the world each year. The clean energy from these units, combined with aggressive renewables deployment, gives us a much better chance of achieving the Paris goals of limiting warming to 1.5°C in the very limited time available.

As the figures above demonstrate, the UK, Japan and South Korea—indeed, most densely-populated and high-energy consuming nations—will not be able to generate enough hydrogen within their own territories to substitute for liquid fossil fuels and natural gas without power dense advanced heat sources. The only credible alternative option is for these countries, if they wish to use renewables as their mainstay option, to import large volumes of liquid fuels from sunny countries in the Middle East and elsewhere. This exposure to liquid fuels commodity markets has geopolitical and energy security implications which are similar to those raised by OPEC and today's oil and gas markets.

Moreover, if renewables-generated price projections for hydrogen are correct, it will be too expensive until after 2040 to substitute green hydrogen for hydrocarbons, and countries like Germany and Japan—if they eschew advanced heat sources—will fail to meet decarbonization targets and still be dependent on fossil fuels for most of their non-electricity energy use as late as mid-century. Needless to say, if this approach is replicated globally, it is not compatible with a 1.5°C or even a 2°C climate pathway. In other words, the insistence on 100% renewables as the only politically acceptable climate mitigation option sharply raises the risks of decarbonization failure and the resulting climate catastrophe.

In contrast, this report has shown that including a major role for advanced heat sources in hydrogen production—while renewables do much of the heavy lifting on electricity sector decarbonization—would allow the world to approach or even meet the goal of net zero carbon emissions by mid-century, as is required in IPCC-validated pathways for a high-probability 1.5–2°C outcome. In our view this presents a truly credible pathway to global net zero carbon emissions—not just because physical realities like land-use scale constraints are taken into account, but because we show a cost-effective path to tackling the difficult-to-decarbonize economic sectors that are ignored or downplayed in most projections. We do this without the need for recourse to large amounts of biofuels, bioenergy with carbon capture and sequestration and air-capture, as are included in virtually all other 1.5°C modeled scenarios. Each of these technologies has serious and well-documented environmental and/or cost implications. Beyond these concerns, the cost of capturing 10 gigatonnes per year for twenty years would be three trillion dollars more than the cost of replacing the global oil industry as proposed in this report. Atmospheric carbon removal does not address the issue at source, but locks in a cost in perpetuity, preventing these funds from being used more productively elsewhere.

In summary, this report has demonstrated that the roadblocks to net zero are not economic or technical. Instead, they are cultural and political. We have shown that by using a new generation of advanced heat sources to generate ultra-cheap clean hydrogen we could choose to rapidly decarbonize the economy and deliver a viable pathway to the Paris goals.

8.2 Recommendations

Maximizing the Opportunity Requires Action without Delay

- **Act now**. This study shows how scalable, cost-effective hydrogen can be produced in the near term. For too long, risks associated with advanced heat sources have been considered outside of the context of risks with other technologies. In addition, these decisions need to be taken with due consideration to the risks of failing to decarbonize. This report is a call to action for leaders to become educated about advanced heat sources, put risks into context and make informed, evidence-based and outcomes-focused decisions having properly evaluated the alternatives. To facilitate such informed decision-making, Government and industry should immediately issue requests for information and seek quotes for shipyard manufactured plants and begin commissioning refinery-scale clean fuels production now.
- **Shipyards are masters of cost, scale, and engineering integration**. We must vigorously invite their capable participation. Their tightly-integrated design and manufacturing processes—combined with onsite steel mills and long-term supply chain relationships offer exactly the needed heavy-manufacturing components and equipment. They offer consistently accurate costing and scheduling. Their advanced manufacturing facilities are certified to meet world-class standards. They regularly deliver complex, highly regulated products.
- **Policy making**. Domestic and global zero-CO_2 hydrogen market development along with existing and emerging global and domestic zero-C hydrogen policy initiatives should be technology inclusive. It should be focused on key outcomes related to cost and scale of production, creation of zero-carbon hydrogen markets, and increased market share for zero-carbon fuels.
- **Access to finance**. In the same way that investors must take a portfolio approach to investments in order to reduce exposure to risk, global efforts to limit climate change should be spread across a portfolio of technology options. Consistent, technology-inclusive access to finance is critical to realizing this.
- **Industry mobilization**. Government and industry need to proactively collaborate to demonstrate determination and capability towards affordable decarbonization and prosperity. This should include demonstration of hydrogen projects at conventional plants, as well as active participation in national and international efforts to accelerate cost-effective commercialization of innovative technologies, delivery and deployment models.
- **Inclusion in climate and energy modeling**. Widespread exclusion of this demonstrated, scalable, and cost-effective clean hydrogen production option from decarbonization pathways has severely limited perceived prospects for tackling climate and increasing global energy access in an affordable and timely manner. By widening the range of technologies available to represent more fully and appropriately the scale of the potential contribution from this proven option, we can both de-risk climate mitigation pathways, while relieving pressure across the whole system clean energy transition and creating more prosperity.

- **Hydrogen fuel industry groups**. (Hydrogen Europe, Hydrogen Council, Ammonia Energy Association, etc.) should seek representation from all clean production sectors, including innovative heat source technology developers to ensure they understand opportunities, and have input on policy development. Heat source developers should be joined up with electrolysis cost reduction, efficiency improvements, and other system developments.

Appendices

Appendix: Sources and Assumptions for Hydrogen Production Cost Estimates

The following tables provide sources and assumptions for the hydrogen production cost estimates used in “Figure 10. Cost of hydrogen production from different energy technologies in the real world now and in 2030” on page 22 and “Figure 11. Projected cost of hydrogen production from different energy technologies in 2050” on page 24 in Section 2.

Table 8. **Sources and Assumptions for Hydrogen Production Cost Estimates (2030)**

Data Point	Description (Source)	Notes
Solar		
Germany (Fraunhofer)	CF:11.48% (1); CapEx: $1,095/kW (2); $750/kWe electrolyzer (3)	2018 solar generation in Germany was 45.7 TWh with total installed capacity at the end of November at 45.5 GW (1). Assumes the higher end of electrolyzer costs in (3); see exhibit 14.
NREL ATB (mid case)	CF: 20% (2); CapEx: $1,095/kW (2); $750/kWe electrolyzer (3)	CF is assumed to be “average” from Kansas City, MO in (2).
NREL ATB (best case)	CF: 27% (2); CapEx: $1,095/kW (2); $750/kWe electrolyzer (3)	CF is assumed to be “best case” from Daggett, CA in (2).
NREL ATB (excellent case)	CF: 27% (2); CapEx: $565kW (2); $400/kWe electrolyzer (3)	Assumes large-scale deployment and learning leads to $400/kW electrolyzer costs, as estimated in (3). CapEx reflects the “low” CapEx case for Kansas City, MO in 2030.
Wind		
NREL ATB; Offshore (mid case)	CF: 45% (2); CapEx: $3,759/kW (2); $750/kWe electrolyzer (3)	CF and CapEx reflects Techno Resources Group (“TRG”) 1 in (2).
NREL ATB (mid case)	CF: 40% (2); CapEx: $1,555/kW (2); $750/kWe electrolyzer (3)	CF and CapEx reflects TRG 5 (mid case) in (2).
Dogger Bank; Offshore (UK)	CF: 63% (4); £40/MWh (5); $610/kWe electrolyzer (3)	Assumes £40/MWh (2012 real prices), which was converted to USD using a 1:1.3 exchange rate and brought to 2019 dollars using (6). Electrolyzer costs are assuming to drop linearly from $750/kW to $400/kW in 2030. Dogger Bank is assumed to be commissioned in 2024.
NREL ATB; Offshore (best case)	CF: 51% (2); $2,117/kWe (2); $400/kWe electrolyzer (3)	CF and CapEx reflects TRG 1 (low case) in (2).
NREL ATB (best case)	CF: 46% (2); $1,252/kWe (2); $400/kWe electrolyzer (3)	CF and CapEx reflects TRG 5 (mid case) in (2).

Data Point	Description (Source)	Notes
Clean Heat		
FOAK (ETI NCD)	CF: 92.2% (2); CapEx: $10,387/kW (7); $397/kWe electrolyzer (8)	CapEx reflects FOAK costs for nuclear plants in the EU and North America in (7). See Table 5 in (8) for electrolyzer costs.
SOAK (ETI NCD)	CF: 92.2% (2); CapEx: $7,271/kW (7); $318/kWe electrolyzer (8)	Assumes a 30% cost reduction in CapEx from a FOAK plant. Assumes a 20% reduction in electrolyzer cost.
US (EEDB)	CF: 92.2% (2); CapEx: $2,867/kW (9): $318/kWe electrolyzer (8)	(9) The 1986 CapEx reported in Table 5-4 ($1,225/kW) was brought to 2019 dollars using the Producer Price Index from (6).
HTGR (JAEA)	CF: 92.2% (2); CapEx: $1,989/kW (10); $318/kWe electrolyzer (8)	See slide 7 in (10) for CapEx costs for the JAEA GTHTR300.
Depreciated PWR*	CF: 92.2%; $14.81/MWh (2), $318/kWe electrolyzer (8)	(2) Fixed O&M costs are converted to $/MWh. This is added to fuel costs. *This scenario assumes that the CapEx has already been recovered and only represents plant OpEx.
New-Build China PWR (Deutsche Bank)	CF: 92.2% (2); CapEx: $1,839/kW (11); $318/kWe electrolyzer (8)	CapEx is sourced from page 43 of (11) and because it was published in the first week of January 2015, CapEx is assumed to be in 2014 dollars.
Shipyard LWR (LucidCatalyst)	CF: 92.2% (2); CapEx: $1,446/kW (12); $280/kWe electrolyzer (8)	Assumes the electrolyzer cost from Table 5 in (8) and subtracts the indirect and land costs.

Notes: CF = Capacity Factor; CapEx = Capitalized Costs; SOAK=Second-of-a-Kind; FOAK=First-of-a-Kind

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Table 9. **Sources and Assumptions for Hydrogen Production Cost Estimates (2050)**

Data Point	Description (Source)	Notes
Solar		
Germany (Fraunhofer)	CF:11.48% (1); CapEx: $683 /kW (2); $250/kWe electrolyzer (3)	2018 solar generation in Germany was 45.7 TWh with total installed capacity at the end of November at 45.5 GW (1). Assumes mid case CapEx for Kansas City in (2) and the lower end of electrolyzer costs in (3); see exhibit 14.
NREL ATB (mid case)	CF: 20% (2); CapEx: $683 /kW (2); $250/kWe electrolyzer (3)	CF is assumed to be "average" from Kansas City, MO (2).
NREL ATB (best case)	CF: 27% (2); CapEx: $356 /kW (2); $250/kWe electrolyzer (3)	CF is assumed to be "best case" from Daggett, CA and CapEx is "low" CapEx case for Kansas City in 2030 in (2).
Wind		
NREL ATB; Offshore (mid case)	CF: 52% (2); CapEx: $1,684/kW (2); $250/kWe electrolyzer (3)	CF and CapEx reflects Techno Resources Group ("TRG") 3 in (2).
NREL ATB (mid case)	CF: 48% (2); CapEx: $1,011/kW (2); $250/kWe electrolyzer (3)	CF and CapEx reflects TRG 5 (mid case) in (2).
NREL ATB (excellent case)	CF: 53% (2); $986 /kWe (2); $250/kWe electrolyzer (3)	CF and CapEx reflects TRG 2 in (2).
NREL ATB: Wind and PV (excellent cases)	CF: 75% (2); $1,367/kWe (2); $250/kWe electrolyzer (3)	CF and CapEx reflect the combination of NREL ATB (best case) for solar PV and NREL ATB (mid case) for wind above.
Clean Heat		
Shipyard-Built Plant	CF: 92.2% (2); CapEx: $700/kW; $140/kWe electrolyzer (4)	Electrolyzer costs are 50% lower than Table 5—less the indirect costs and land—in (8) for electrolyzer costs.
Adv. Reactor: Flexible H_2 and Power	CF: 70% (2); CapEx: $700/kW; $140/kWe electrolyzer (4)	Electrolyzer costs are 50% lower than Table 5—less the indirect costs and land—in (8) for electrolyzer costs. Assumes that H_2 is made 70% of the time (the rest of the time is power generation).
H_2 Gigafactory	CF: 95% (2); CapEx: $835/kWe; $309/kWe electrolyzer (5)	The electrolyzer cost of $309/kW derived from a General Atomics cost study and reduced using chemical plant scaling (and the economies of scale of the plant size).

Notes: CF = Capacity Factor; CapEx = Capitalized Costs

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Endnotes

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