Transporting Hydrogen vs. Transporting Electricity and the Relative Locations of Supply, Storage and Demand[a]

Introduction and Summary

This note contains comments on whether it is cheaper to transport hydrogen than electricity (a question which was raised during the meeting on 8/9/23 when the report was launched), and on the relative locations of supply, storage and demand.

Estimates of the cost of building power lines in GB are available, but a quick search did not come up with GB costs for constructing hydrogen pipelines. The capital cost of transporting hydrogen per MW-mile in pipelines is required, but i) estimates of costs, which vary widely, are often only reported per mile or per MWh, and ii) depend sensitively on the size of the pipe, the assumed pressure, the rate of gas flow, the terrain etc. An added complication is that, for both hydrogen and electricity, the estimates that are available were made at different times, and therefore need to be corrected for inflation, in different currencies.

To simplify the analysis, the extreme cases that all energy is transmitted from wind and solar farms to hydrogen stores *either* by electricity *or* by hydrogen were considered. The way that energy is transmitted from stores to the grid is not considered as the distances involved – and the effect on the cost – are relatively small (recall that the report considers the cost of electricity fed into the grid before transmission and distribution to consumers).

The conclusions are that

1. Transmitting all hydrogen in pipes with a diameter greater than 40 cm appears to be cheaper than transmitting electricity. However, smaller pipes would be used for links to individual solar and wind farms.
2. The optimum way to transport energy to and from storage cannot be definitively identified without a detailed study based on better understanding of unit costs and the location of wind and solar farms, storage and demand. A mixture could be the best option, especially if re-purposed gas pipelines could provide part of the long-distance transmission.
3. There is a need for comparative studies, with common transparent assumptions, of the cost of transporting hydrogen and electricity in GB and European conditions (the only such studies identified in a quick search are for the US).
4. If electricity is used to transport energy all the way from wind and solar farms to electrolysers placed next to stores, substantial modifications of the grid will be needed. However, it turns out that the impact on the average cost of electricity found by assuming that transport from farms to electrolysers i) piggy-backs on the use of the grid to transport energy to meet demand (as done in the report[b]), and ii) uses new dedicated transmission lines, is much the same.
5. The configurations of the grid and the parameters of the storage system should be optimised jointly. In finding the lowest cost combination of electrolyser power and storage capacity, the storage system was treated in isolation in the report. If (as is likely) the transmission cost contains an element that depends on the electrolyser power,

[a] Note written by Chris Llewellyn Smith, with input from Mike Muskett, Seamus Garvey and Richard Nayak-Luke

[b] Where the total cost of hydrogen transport was overestimated for reasons explained on page 93 of the Supplementary Information.

taking it into account would lead to lower electrolyser power and a larger storage capacity, and a different level of wind and solar generation.

6. The availability of water could constrain the location of electrolysers. However, using sea water, desalinated using reversed osmosis, rather than fresh water, would have a negligible impact on the average cost of electricity. This would be certainly be possible for electrolysers located close to salt caverns, which will preferentially be sited close to the sea to facilitate brine disposal when they are solution-mined.

Loads

Figure 1 shows the loads on various links in the transmission chain in the case (modelled in Fig 13 in the report) that all storage is provided by hydrogen with 89.4 GW of electrolyser power (the conclusions are not sensitive to this number).

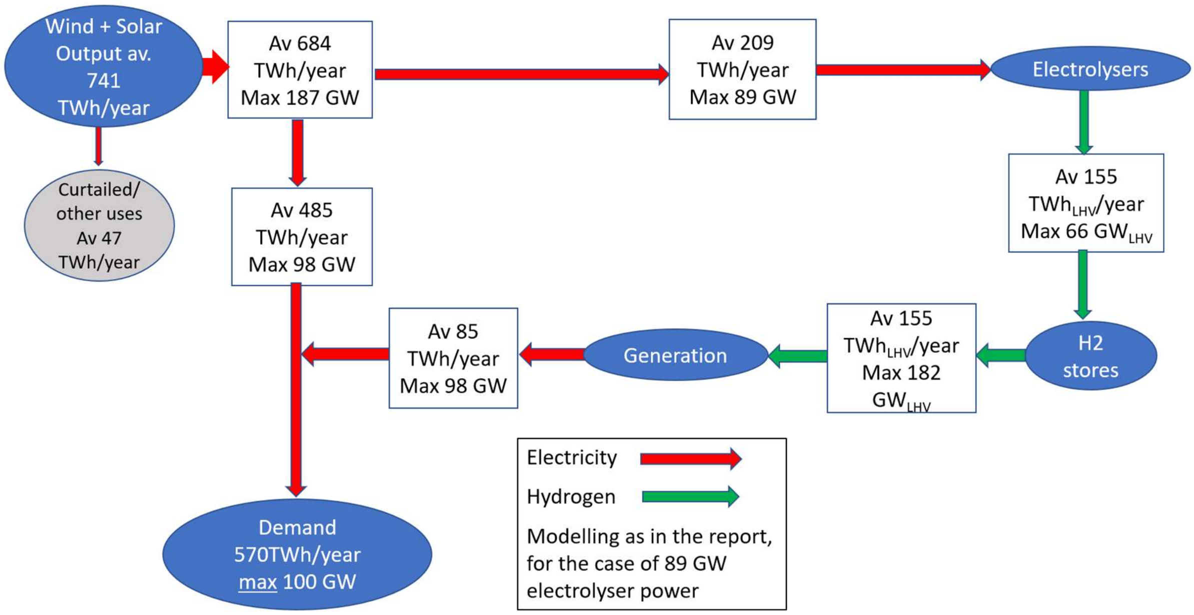

Figure 1. *In the text, extremes cases are analysed in which all electrolysers are located* either *adjacent to wind and solar farms (in which case the top line would shrink to a point) or adjacent to stores (in which case the line between electrolysers and stores would shrink to a point). In reality they could be located anywhere on the route from wind and solar farms to stores in a way that minimises the cost.*

This figure shows that if all energy is transmitted to storage electrically, the impact on the grid would be more than marginal, e.g. for the flow of wind generated electricity in Scotland to storage in East Yorkshire and southwards to meet demand.

It turns out that, as discussed in an Appendix to this note, the maximum need for power to meet demand (98.3 GW) can almost exactly coincide with the maximum supplied to electrolysers (89.4). Hence in the (possibly extreme case) that there is an initial stage in which electric power is transmitted jointly to electrolysers and to meet demand, the power line would have to have a capacity of 186.1 GW, close to the theoretical maximum of 98.3 + 89.4 = 187.7 GW. However, such a coincidence happens rarely, and it would be possible to restrict the flow of power in the initial stage, and compensate for the loss of supply by increasing the electrolyser capacity (which would then provide more hydrogen when the restriction is not in force) and/or reducing demand. This possibility, which is discussed in the Appendix, provides an example of the potential benefits of optimising the configurations of storage and the grid jointly.

Unit costs

Electricity

Costs for a 450 kV overhead power line in GB were taken from the table below, which can be found in a report by Parsons Brinckerhoff, which was endorsed by the Institution of Engineering and Technology, and launched in 2012[1] https://www.theiet.org/impact-society/factfiles/energy-factfiles/energy-generation-and-policy/electricity-transmission-costing/

Lifetime Cost Results (£4.0m/km; £580/MVA-km)

Fixed Build Cost	£3.2m	**Other Results**
Variable Build Cost	£131.4m	Losses = 54% of Lifetime Cost for 75km
Build Cost Total for 75km	**£134.6m**	
plus Variable Operating Cost	£166.9m	Costs most sensitive to:
Lifetime Cost for 75km	**£301.5m**	• Average circuit loading: -40.3% to 67.2%
Lifetime Cost for 75km	£301.5m	• Route length: -49.4% to 49.4%
divided by route length	÷ 75km	
Lifetime Cost per km	**£4.0m/km**	
Lifetime Cost per km	£4.0m/km	**Notes (Jan-12)**
divided by Power Transfer	÷ 6930 MVA	
Lifetime PTC* per km	**£580/MVA-km**	* PTC = Power Transfer Cost

The lifetime cost of £580/MW-km corresponds to £580*1.6 (km/mile)/14.1 (discount factor) = £66/MW-mile/year, where the discount rate (6.5%) and lifetime (40 years) used to discount future energy flows are those that were used by Parsons Brinckerhoff in discounting losses. However:

- Losses, which were assumed to contribute £162 M to the lifetime cost for 75 km (maintenance only contributes £4.9m), depend on the assumed peak and off-peak cost of power and the load factor, which will only be 26% for transmission to electrolysers, on the other hand
- Costs depend on distances, capacities, voltages, and also discount rates, while
- Prices have risen by over 50% (using the CPI) since the report was written.

Conclusion: Taking account of inflation, £100/MW-mile/year is a reasonable figure to use in estimating the scale of the cost of transmission from wind and solar farms to storage (but may be on the high side given the low load factor, and hence relatively low losses).

This magnitude of this cost is in line with costs found in US studies, although detailed comparisons are not possible as the conditions are different and different assumptions were made (on distances, terrain etc.).

Hydrogen

Transport costs were used from two sources:

1. A 2022 paper by De Santis et al[2], which compares the costs of transporting hydrogen and electricity over 1000 miles in US conditions. It finds a capital cost of \$166/MW$_{LHV}$-

mile for a building a hydrogen pipeline[c], although Figure 3 gives a 90% confidence upper limit of around \$930/MW_{LHV}-mile.

2. A 2013 paper by Baufumé et al[3], which was used by the IEA in making estimates of hydrogen transport that are provided in an annex[4] to their 2019 report for the G20 on the Future of Hydrogen[d]. This paper implies a capital cost of €$_{2010}$876/MW-mile This is for a 40 cm diameter pipe that transports hydrogen at 15 m/s at 100 bar, whereas DeSantis et al. assume a 36" pipe transporting hydrogen at 18.5 m/s at 100 bar. Baufumé et al give the cost as a function of diameter, and their paper implies a cost of €$_{2010}$511/MW-mile for a 36" pipeline. This is obviously much higher than found by DeSantis et al., although below S DeSantis et al.'s 90% confidence limit (comfortably with the exchange rate of 0.94\$/€ on 22/9/23).

In view of the large range, and the multiple variables involved, a range of a cost will be used below for long-distance transmission

£135/MW-mile (De Santis et al.)

£444/MW-mile (Baufumé et al.) 36" pipe reference cost

£762/MW-mile (Baufumé et al.) 40 cm pipe reference cost

£981/MW-mile (Baufumé et al.) 40 cm pipe upper cost

Other estimates are available (e.g. those made by Semeraro[5], whose paper contains a wealth of detail, but in providing bottom line numbers focusses on particular cases of hydrogen generated by wind energy), but the range above is sufficient for present purposes. The range of estimates that are available is indicated by the costs below for transmission in large pipelines in \$million/mile, reported by Statista[6], which also show that the use of re-purposed gas pipelines would be very cost-effective

Onshore:	Repurposed 0.6-1.2
	New 2.2-4.5
S Subsea:	Repurposed 1.3-3.1
	New 4.7-7.1

Costs of transmission from wind and solar farms to storage

Cost will be estimated in the extreme cases that **either**

1. Electricity is transmitted from wind and solar farms to electrolysers next to the stores by dedicated purpose-built on-shore AC power lines (although some power will be transmitted subsea, and - see the next section - the National Grid is considering long-distance underseas transmission linking Scotland and England)

or

2. Hydrogen is transmitted from electrolysers next to wind and solar farms to stores by purpose-built pipelines (this can't be exactly true unless electrolysers were located on all offshore wind farms)

and

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[c] This paper, which quotes other – higher – estimates, gives a capital cost of \$1,502/MW-mile for transmitting electricity over 1000 miles in an HVDC power line. For shorter distances, AC is cheaper than DC, but nevertheless this suggests that transporting hydrogen in large pipelines is a lot cheaper than transmitting electricity.

[d] The IEA quote and use a cost formula given by Baufumé et al. which turns out to be for their 'upper cost'. Their reference case is 22% cheaper. The IEA assumed that this formula gives the costs in \$s, but it is clearly in €s in the original paper.

and

that the average distance from wind and solar farms to the stores is 200 miles (it is a trivial matter to change this assumption: 200 miles is probably too much (it would certainly be too much if aquifers were used for storage), although note that it is 350 miles from Peterhead to Aldborough in E Yorkshire), and no allowance will be made for the higher cost/mile of bringing power onshore from wind farms than transmitting it on land. Transmission from stores to generators to the grid will not be analysed on the grounds that distances from stores to the grid will be relatively short, and the cost should be covered by the generous assumption of 200 miles.

The same discount rate (6.5%) and lifetime (40 years) will be used to discount future energy flows as were used by Parsons Brinckerhoff in discounting losses, and used above to estimate the annual cost of transmitting electricity.

Electricity

With electrolysers next to store and the unit costs above, the cost of transmitting a maximum of 89.4 GWe would be

£100 (unit cost/MW)*200 (miles)*89.4 (GWe)*10^3= £1,788*10^6/year

With 570 TWh/year demand, 'all electric' transmission would add £(1788/570 = 3.1)/MWh to the average cost of electricity (but £21/MWh to the cost of the 85 TWh/t year provided by storage).

Reassuringly, this is close to the £3/MWh included in overall costs in the report in which it was assumed that transmission piggy-backs on the use of the grid to transmit power to meet demand.

Hydrogen

With electrolysers next to wind and solar farms, the unit costs above, and the assumption (made by De Santis et al.) that operation would cost 10% of capex/year, with the US (de Santis) cost estimate and a 36" pipeline the cost the cost of transmitting a maximum of 61 GW_{LHV} would be

£135 (lifetime cost/MW)*(1/14.1(discount factor) + 0.1 (operation cost)) *200(miles) *66.2(GW_{LHV})*10^3= £306*10^6/year,

which would add £306/570= £0.54/MWh to the average cost of electricity.

The same sequence of steps leads to the cost in the following table in other cases:

Source	Size of pipe	Annual cost £/year	Contribution to the averge cost of electricity £/MWh
US cost 2022[2]	36"	306	0.63
German cost 2013[3] – *needs updating for inflation*	36" reference case	1007	1.77
	40 cm reference case	1726	3.03
	40 cm upper costs	2225	3.90

At least with large pipes, transmitting hydrogen appears to be cheaper than transmitting electricity[e] (although caution is needed as the estimate of electricity costs has a significant

[e] This is true even with DeSantis et al.'s 90% confidence limit upper bound, which would lead to an addition of £2.8/MWh to the average cost of electricity.

margin of uncertainty), because i) the unit costs are lower, and ii) less power has to be transmitted after electrolysis. However, these estimates assume that all transmission of hydrogen is by large capacity pipes (40 cm or more), and of electricity at the high voltage appropriate for transmission rather than distribution. This won't be true for links to individual solar and wind farms.

Inputs to a full analysis of transmission costs

A proper study of transmission costs would require a model of the location of supply, demand and storage, and many other factors. One factor, which was not dicussed in the report, is the availability of water for electrolysis. In England, 10 x 10^9 m^3 of ground water are extracted every year. In the all hydrogen storage case shown in the figure above, 0.4% of this would be needed on average to meet GB's storage needs. Unless the electrolysers were widely distributed in the area between wind and solar farm and the salt caverns used for storage, which will be located in a few regions, providing this water would be a challenge. However, if the electrolysers are close to the caverns, which will have to be close to the sea to enable brine disposal when they are solution-mined (unless the brine can be fed into saline aquifers), desalinated sea water could be used. The cost of reverse osmosis is now down to \$0.5/m^3 in the best cases[7]. A cost of \$1/m^3 would only add \$0.49/MWh_e to the cost electricity provided by storage (and \$0.07/MWh_e to the average cost of electricity). Alternatively, water drawn from saline aquifers, and desalinated, could be used.

Other factors that need to be considered include:

- Detailed knowledge of the existing and planned grid, and assumptions on whether there will be an offshore grid connecting different wind farms model (which everyone agrees is needed) - see comments on Pathway to 2030 below.
- The terrain and population density, and planning issues, that must be considered in planning the grid, are also vital elements in planning hydrogen pipelines.
- A model of transmission that takes account of timing, and can identify bottlenecks/grid congestion (needed *inter alia* to study the extent to which provision of power for storage and to meet demand should be integrated) - see comments on Pathway to 2030 below.
- Better unit costs for transmitting electricity (on and off shore), for different capacities, at different voltages.
- Better unit costs for transmitting hydrogen (on and off shore).
- Joint optimisation of the configuration of the grid and storage.
- ......

The ESO's report Pathway to 2030 - A holistic network design to support offshore wind deployment for net zero[8] provides very interesting information on development of the grid, including (Figs 1 and 2) maps that show subsea connections between England and Scotland, and between different wind farms. The report foresees that, compared to radial connections, the connections between wind farms will yield *Overall net consumer savings of approximately £5.5 billion. The recommended design leads to an additional £7.6 billion of capital costs due to the additional offshore infrastructure, but this is outweighed by the £13.1 billion savings in constraint costs.*

Appendix

Figure A1 below shows that maximum demand (of 98.3 GW) occasionally almost exactly coincides with the maximum that has to be fed to electrolysers (82.3 GW). If there is an initial stage in which electric power is transmitted jointly to electrolysers and to meet demand, it turns out that the power line would have to have a capacity of 186.1 GW, close to the theoretical maximum of 98.3 + 89.4 = 187.7 GW which would have been found if there had been an exact coincidence.

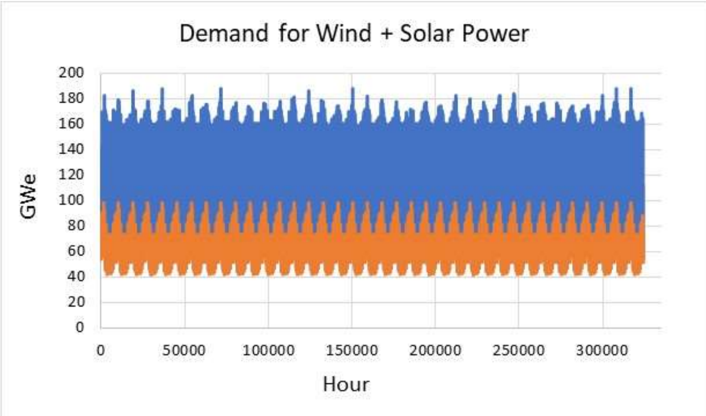
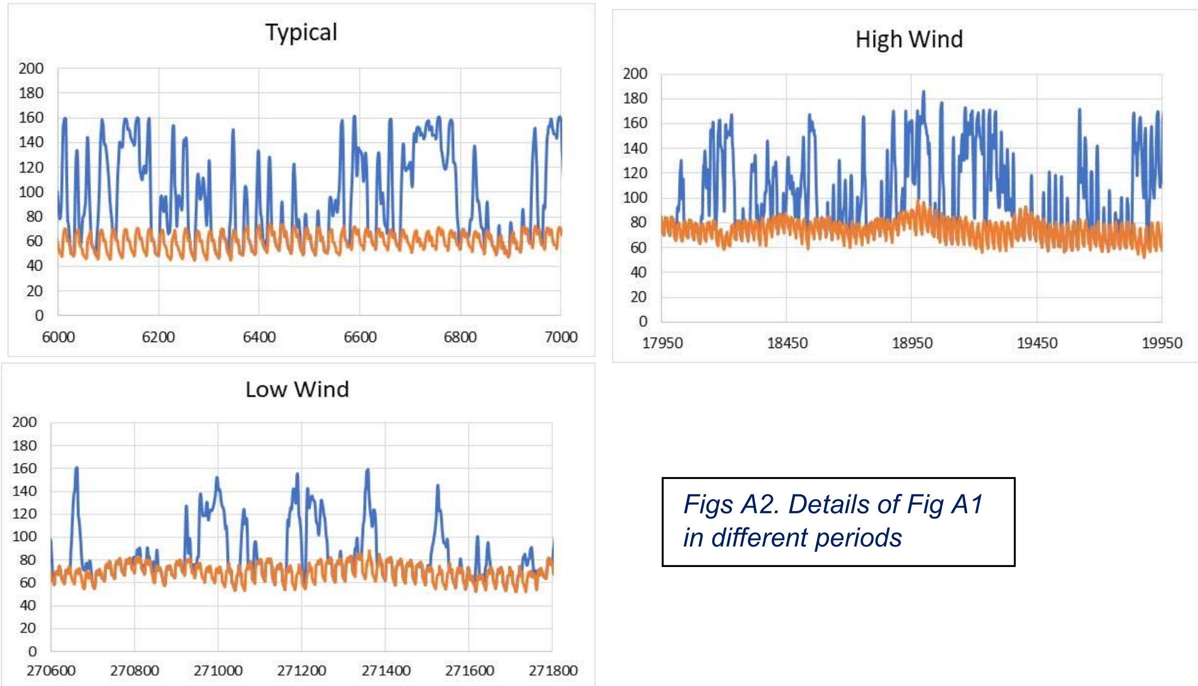


Figure A1. Here, for every hour in the 37 years studied: ***orange*** *= demand, which is met directly by wind & solar when supply > demand, and by wind & solar + electricity from store when supply < demand:* ***blue*** *= wind & solar power provided to electrolyser (0 when supply < demand)* ***+*** *power to meet demand*

(all directly if supply > demand; partly directly, partly when supply < demand).

Fig A1 shows that occasionally 186.1 GW must be provided but he resolution not good enough to show structure. Figs A2 show the structure in different periods.



Figs A2. Details of Fig A1 in different periods

Fig A3 shows the number of hours in 37 years (x-axis) during which, if there is an initial stage 1 in which electric power is transmitted jointly to electrolysers and to meet demand, it would have to transmit a given amount of power.

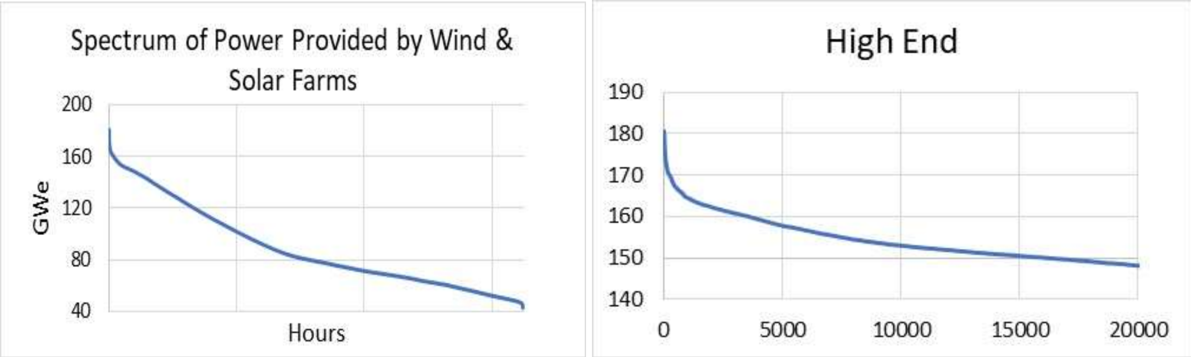


Fig A3. *Number of hours in 37 years (x-axis) during which a possible stage 1 of the transmission chain would have to transmit a given amount of power.*

The power above (say) 150 GW is very seldom needed. If stage 1 could not carry more than 150 GW, not all demand could be met. However, the effect on the energy balance would be small, as shown in the following table[f] for restrictions of 130, 140, 150 and 155 GW.

Stage 1 restriction	Av unmet demand TWh/year	Av hours/year restriction in force	Av energy from electrolysis when restriction not in force TWh/year	Col 2/Col 3
< 130 GW	24	1332	176.9	0.136
< 140 GW	13	945	186.1	0.068
< 150 GW	4.8	476	194.2	0.024
<155 GW	2.5	387	198.7	0.013

A restriction to less than 155 GW in stage 1, which would lead to a 17% reduction in the power capacity needed in stage1, would leave 2.5 TWh/year of demand. This could ***either*** be met by a 1.3% increase in electrolyser power which, in the hours when the restriction on stage 1 power is not in force, would provide 1.26% (col 5) of 198.7 (col 4) = 2.5 TWh, ***or*** be compensated by demand reductions averaging 2.6 TWh/year. The saving resulting from reducing the power demand in stage 1 by 17% could be greater than the cost of providing an additional 1.3% of electrolyser power, depending on how the grid is configured, while it should be relatively easy to reduce demand by an average of 2.6 TWh/year. More stringent restrictions would require bigger changes/more demand management, which might or might not be desirable/achievable.

This possibility is provided purely as a hypothetical example of the possible benefits of optimising the grid configuration and the storage system together. Full optimisation would require consideration of the entire transmission and storage system, taking account of the multiple factors identified above

[f] Col 2 + Col 3 + Energy provided by electrolysers when the restriction is in force = 209 TWh/year, as required

References

[1] Electricity Transmission Costing Study https://www.theiet.org/impact-society/factfiles/energy-factfiles/energy-generation-and-policy/electricity-transmission-costing/

[2] D DeSantis et al iScience 24, 103495, 2021 https://doi.org/10.1016/j.isci.2021.103495

[3] S Baufumé et al International Journal of Hydrogen Energy, 38,10, 2013, 3813

[4] The Future of Hydrogen Assumptions annex IEA G20 Hydrogen report https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions

[5] Michael Semeraro, Energy Strategy Reviews 35 (2021) 100658 https://doi.org/10.1016/j.esr.2021.100658

[6] https://www.statista.com/statistics/1220856/capex-new-retrofitted-h2-pipelines-by-type/

[7] N Ghaffour et al http://hdl.handle.net/10754/562573

[8] https://www.nationalgrideso.com/document/262676/download